BOARD MEETING DATE: November 5, 2021 AGENDA NO. 34

PROPOSAL: Certify the Final Subsequent Environmental Assessment for Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen From Petroleum Refineries and Related Operations, Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations, Proposed Amended Rule 1304 – Exemptions, Proposed Amended Rule 2005 – New Source Review for RECLAIM, and Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries; and Adopt Rules 1109.1 and 429.1, Amend Rules 1304 and 2005, and Rescind Rule 1109

SYNOPSIS: Proposed Rule 1109.1 (PR 1109.1) establishes NOx and CO emission limits for combustion equipment at petroleum refineries and facilities with operations related to petroleum refineries. PR 1109.1 includes an alternative implementation plan referred to as an I-Plan, and two alternative BARCT plans referred to as a B-Plan and a B-Cap. To provide transparency and minimize delays with approving an I-Plan, B-Plan, or B-Cap, PR 1109.1 includes a process to pre-approve emissions data used for these plans which are included in the "Baseline NOx Emissions and Representative NOx Concentrations for Facilities Regulated Under Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations." Implementation of PR 1109.1 is expected to achieve reductions of 7.7 to 7.9 tons per day of NOx. Proposed Rule 429.1 (PR 429.1) provides an exemption from the NOx and CO concentration limits in PR 1109.1 during startup, shutdown, commissioning, and certain maintenance events. Proposed Amended Rule 1304 (PAR 1304) and Proposed Amended Rule 2005 (PAR 2005) implement a narrow BACT exemption for PM10 and SOx emission increases associated with installation of new and modified add-on air pollution control equipment installations or modifications that are needed to meet the NOx limits under PR 1109.1. Proposed Rescinded Rule 1109 is obsolete with the adoption of PR 1109.1.

COMMITTEE: Stationary Source, PR 1109.1 September 18, 2020, February 29, 2021, March 19, 2021, June 18, 2021, and September 17, 2021; and PR 429.1, PARs 1304 and 2005, and Proposed Rescinded Rule 1109 September 17, 2021, Reviewed

RECOMMENDED ACTIONS:
Adopt the attached Resolution:
1. Certifying the Final Subsequent Environmental Assessment for Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen From Petroleum Refineries and Related Operations, Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations, Proposed Amended Rule 1304 – Exemptions, Proposed Amended Rule 2005 – New Source Review for RECLAIM, and Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries;
2. Adopting Rules 1109.1 and 429.1, Amending Rules 1304 and 2005, and Rescinding Rule 1109; and
3. Approving the "Baseline NOx Emissions and Representative NOx Concentrations for Facilities Regulated Under Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations," November 5, 2021.

Wayne Nastri
Executive Officer

SR:SN:MK:MM

Background
The South Coast AQMD Board adopted the RECLAIM program in 1993 to achieve emission reductions in aggregate equivalent to or greater than what would occur under a command-and-control regulatory approach. During the adoption of the 2016 AQMP, the Resolution directed staff to modify Control Measure CMB-05 to achieve five tons per day NOx emission reduction as soon as feasible but no later than 2025, and to transition the RECLAIM program to a command-and-control regulatory structure. Additionally, California State Assembly Bill 617 – Nonvehicular Air Pollution: Criteria Air Pollutants and Toxic Air Contaminants (AB 617) was adopted in 2017 and requires an expedited schedule for implementing BARCT for facilities in the state greenhouse gas cap-and-trade program which includes refineries and facilities with related operations.

Petroleum refineries and facilities with operations related to petroleum refineries represent the largest source of NOx emissions in the RECLAIM program. Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR 1109.1) establishes BARCT NOx and CO concentration limits for combustion equipment located at sixteen facilities, which include five major petroleum refineries and facilities with operations related to petroleum refineries as required under

AB 617. PR 1109.1 is designed to partially implement CMB-05 of the Final 2016 AQMP and is needed to transition refineries and facilities with related operations from the RECLAIM program to a command-and-control regulatory structure. Implementation of PR 1109.1 is expected to achieve 7.7 to 7.9 tons per day of NOx emission reductions. Approximately 220 pieces of NOx equipment will need to be modified to meet the proposed NOx limits under PR 1109.1.

There are three companion rules to support implementation of PR 1109.1. Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations (PR 429.1) provides an exemption from the NOx and CO concentration limits in PR 1109.1 during startup, shutdown, commissioning, and certain maintenance events. Proposed Amended Rule 1304 – Exemptions (PAR 1304) and Proposed Amended Rule 2005 – New Source Review for RECLAIM (PAR 2005) provide a narrow BACT exemption for installation of add-on air pollution control equipment needed to meet the NOx concentration limits in PR 1109.1. Rule 1109 which regulated large refinery boilers and process heaters prior to the RECLAIM is proposed to be rescinded as it will no longer be needed.

Public Process

Development of this suite of rules was conducted through a public process. Working group meetings included environmental and community groups, industry representatives, other agencies, and equipment vendors. The rule development process for PR 1109.1 began in 2018 and included 25 working group meetings and two community meetings. PR 429.1 was discussed at three of the PR 1109.1 working group meetings. PAR 1304 and PAR 2005 was discussed at six PR 1109.1 working group meetings and five Regulation XIII working group meetings. In addition, staff held over 100 individual meetings with stakeholders to discuss specific rule issues. A Public Workshop for all the proposed rulemakings was held on September 1, 2021. Due to COVID-19 and in accordance with the Governor's Executive Order N-29-20, all public meetings after March 18, 2020 were conducted remotely via video conferencing and teleconferencing.

Throughout the rulemaking process, meetings were held with individual stakeholders, U.S. EPA and CARB. In January 2021, staff initiated individual meetings with the five major petroleum refineries and environmental and community groups. Since January 2021, staff has held over 60 meetings with Chevron Products Co., Marathon Petroleum Corporation (Tesoro Refining and Marketing Company, LLC), Phillips 66 Company Los Angeles Refinery, Torrance Refining Company LLC, and Ultramar Inc. (Valero Refinery). Since February 2021, staff held nearly 20 meetings with representatives of Earth Justice, Coalition for Clean Air, Natural Resources Defense Council, and Communities for a Better Environment. Beginning May 2021, staff began meeting weekly with the Western State Petroleum Association in response to their proposal for an alternative BARCT approach for the RECLAIM transition. Staff also met periodically, with other facilities subject to the proposed rule: Air Products and

Chemicals, Inc., AltAir Paramount, Eco-Services Operations, LLC, and Lunday-Thagard Co Dba World Oil Refining.

Proposed Rules and Amendments
PR 1109.1 establishes NOx and CO concentration limits for petroleum refineries and facilities with operations related to petroleum refineries, which includes asphalt plants, biofuel plants, hydrogen production plants, facilities that operate petroleum coke calciners, sulfuric acid plants, and sulfur recovery plants at petroleum refineries. A robust BARCT analysis was conducted to establish the NOx and CO concentration limits for each class and category of equipment that included a technology assessment, cost-effectiveness, and incremental cost-effectiveness analysis. Under PR 1109.1 the core NOx concentration limits that represent BARCT are in Table 1 – NOx and CO Concentration Limits. To address units with high outlier cost-effectiveness estimates and to ensure that each class and category has a cost-effectiveness below $50,000 per ton of NOx reduced, PR 1109.1 has alternative BARCT NOx concentration limits that are higher than Table 1 NOx concentration limits, listed in Table 2 – Conditional NOx and CO Concentration Limits. An operator that elects to meet the Table 2 conditional NOx concentration limits in lieu of Table 1 NOx concentration limits, must first demonstrate that the unit will meet six distinct conditions that are designed to minimize any loss of cost-effective NOx reductions.

Even with the allowance of Table 2 conditional NOx concentration limits, implementation of PR 1109.1 is expected to result in significant capital investments ranging from $180 million to $1 billion per refinery. In addition, implementation of PR 1109.1 is expected to require approximately 70 new selective catalytic reduction (SCR) systems, and upgrades to approximately 30 existing SCR systems, which are customized projects that require engineering designs and specifications that are unique to each individual unit. To address the cost and complexity to achieve the proposed NOx limits, PR 1109.1 includes two alternative compliance plans to achieve the BARCT NOx concentration limits in Table 1 and Table 2 (B-Plan and B-Cap), and an alternative implementation schedule plan (I-Plan). The B-Plan, B-Cap, and I-Plan provide compliance flexibility while achieving the same NOx reductions that would occur if an operator were to directly meet the NOx limits in Table 1 and Table 2. PR 1109.1 also includes provisions for using alternative compliance plans, the approval process, and when an approved plan must be modified.

To ensure there is no backsliding of emissions as required under the federal Clean Air Act Section 110(l), PR 1109.1 includes interim NOx limits for units that would apply after the facility transitions out of RECLAIM and until the unit is in full compliance with the PR 1109.1. In addition, PR 1109.1 includes monitoring, recordkeeping, and reporting requirements and exemptions for low-use units and other units that are exempt from the proposed rule. Upon adoption of PR 1109.1, Rule 1109 which is a source-specific rule for refinery boilers and heaters will be rescinded as it will be no longer be needed.

PR 429.1 provides an exemption from the NOx and CO concentration limits in PR 1109.1 during startup, shutdown, commissioning, and certain maintenance events. PR 429.1 establishes provisions for startup, shutdown, and certain maintenance events, and notification and recordkeeping provisions for units that are subject to PR 1109.1. PR 429.1 establishes requirements during startup and shutdown, such as limiting the duration of time that an operator is exempt from NOx and CO concentration limits during startup and shutdown and the frequency of scheduled startups.

PAR 1304 and PAR 2005 provide a narrow BACT exemption for PM10 emission increases caused by the installation or modification of add-on air pollution control equipment, such as SCR, and increases in PM10 and SOx emissions associated with existing basic equipment replacements that are combined with the installation or modification of add-on air pollution control equipment, that will be needed to meet the NOx concentration limits under PR 1109.1. The BACT exemption in PAR 1304 is limited to RECLAIM or former RECLAIM facilities complying with a NOx BARCT emission limit that is part of the transition from NOx RECLAIM to a command-and-control regulatory structure. Operators that elect to use this exemption must meet a series of conditions, which includes a provision that any increase in PM and SOx emissions cannot exceed federal New Source Review thresholds. The proposed provision in PAR 2005 allows a RECLAIM facility replacing existing basic equipment that is combined with the installation or modification of air pollution control equipment to comply with a command-and-control NOx emission limit for a Regulation XI rule, to apply the BACT requirement for a SOx emission increase under Rule 1303 – Requirements, instead of BACT under Rule 2005 and use the limited BACT exemption in PAR 1304 subdivision (f).

NOx Emissions for the B-Plan and B-Cap
During the rulemaking process, environmental and community groups highlighted the importance that there should be no delay in approving the I-Plans, B-Plans, and B-Caps, with the primary concern regarding potential delays associated with emissions data used to establish the emission targets for these plans. To address this issue, PR 1109.1 establishes a Board approved process to establish the NOx baseline emissions and concentrations. The first step in the process is the approval of the emissions data "Baseline NOx Emissions and Representative NOx Concentrations for Facilities Regulated Under Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations," which is included as an attachment to this package. Staff has worked with each operator to finalize this emissions data for each unit. Operators will have 30 days to make revisions, and any revision that is greater than five percent will be presented to the Stationary Source Committee no later than February 18, 2022. After changes are presented to the Stationary Source Committee, if any, operators cannot modify the Baseline NOx Emissions or Representative NOx Concentrations for any Unit, and must use the approved values for all emissions calculations for the I-Plan,

B-Plan, and B-Cap. This approach provides greater transparency and is expected to help reduce delays with approving I-Plans, B-Plans, and B-Caps.

Key Issues and Remaining Issues

Throughout the rulemaking process, staff worked with stakeholders to address and resolve a number of key issues. Notable issues that were resolved through the rulemaking process were agreeing that RTCs would not be used to meet PR 1109.1 interim provisions, incorporating revised facility cost estimates into the cost-effectiveness analysis, incorporating the incremental cost-effectiveness prior to establishing a proposed BARCT limit, developing an exemption for co-pollutant emissions for SCR systems used to meet PR 1109.1 NOx limits, incorporating a ten percent environmental benefit in the B-Cap, and incorporating compliance flexibility without forgoing NOx reductions.

Environmental and community groups have consistently expressed the importance of adopting PR 1109.1, particularly for the communities that live around petroleum refineries. Although staff has received comments regarding the added flexibility and long implementation timeframe allowed under PR 1109.1, environmental and community groups have commented that they also recognize the complexity and high cost associated with PR 1109.1 and the fundamental need to adopt PR 1109.1. Based on recent discussions, environmental and community groups commented that PR 1109.1 is not consistent with AB 617[1] which requires "implementation of best available retrofit control technology (BARCT), by the earliest feasible date, but in any event not later than December 31, 2023."

PR 1109.1 implements expedited BARCT in accordance with AB 617 by December 31, 2023 while delivering additional NOx emission reductions representative of BARCT beyond 2023. Staff estimates that 3.7 to 3.8 tons per day of NOx emission reductions, or 50 percent of the overall rule reductions, will be achieved by December 31, 2023. Those emission reductions are the result of the NOx emission reduction projects currently being implemented, units that will likely achieve early reductions complying with Table 2 conditional limits and the largest refinery in the region reducing 50 percent of the required PR 1109.1 reductions by January 1, 2024. PR 1109.1 goes beyond AB 617 by establishing lower NOx limits to achieve additional NOx reductions beyond December 31, 2023. PR 1109.1 will achieve an additional 4.0 to 4.1 tons per day of NOx emission reductions beyond December 31, 2023, which provides an overall NOx reduction of 7.7 to 7.9 tons per day. This approach ensures compliance with expedited BARCT by achieving reductions by 2023, while requiring the lowest achievable NOx limits to maximize emission consistent with the definition of BARCT. In addition, this will provide greater health benefits for the communities that live around these facilities and substantial progress towards achieving attainment of the federal ozone standards.

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[1] Health and Safety Code Section 40920.6 (c)(1).

California Environmental Quality Act
PR 1109.1, PR 429.1, PAR 1304, PAR 2005, and Proposed Rescinded Rule (PRR) 1109 are considered a project as defined by the California Environmental Quality Act (CEQA) and the South Coast AQMD is the designated lead agency. Pursuant to South Coast AQMD's Certified Regulatory Program (Public Resources Code Section 21080.5 and CEQA Guidelines Section 15251(l); codified in South Coast AQMD Rule 110) and CEQA Guidelines Section 15187, the South Coast AQMD has prepared a Subsequent Environmental Assessment (SEA) for the proposed project, which is a substitute CEQA document pursuant to CEQA Guidelines Section 15252, prepared in lieu of a Subsequent Environmental Impact Report. The environmental analysis in the SEA tiers off of the December 2015 Final Program Environmental Assessment (PEA) for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM) (referred to as NOx RECLAIM) and the March 2017 Final Program Environmental Impact Report (EIR) for the 2016 Air Quality Management Plan (AQMP) as allowed by CEQA Guidelines Sections 15152, 15162, 15168 and 15385. Because the SEA is a subsequent document to the December 2015 Final PEA for NOx RECLAIM, the baseline is the project analyzed in the December 2015 Final PEA for NOx RECLAIM. Implementation of the proposed project is estimated to reduce NOx emissions by approximately 7 to 8 tpd, while not increasing CO emissions. If the minimum 7 tpd of NOx emission reductions is achieved, a corresponding regionwide net decrease in annual PM2.5 concentration of 0.11 micrograms per cubic meter is also expected. The analysis of the proposed project in the SEA indicated that substantial increases in the severity of the significant effects that were previously examined in the December 2015 Final PEA for NOx RECLAIM would occur. [CEQA Guidelines Section 15162(a)(3)(B)]. The Final SEA concluded that the proposed project would generate significant adverse environmental impacts for the topics of: 1) air quality during construction and greenhouse gases; 2) hazards and hazardous materials associated with ammonia; and 3) hydrology. The Final SEA is included as an attachment to this Board package (see Attachment U). In addition, Findings pursuant to CEQA Guidelines Section 15091, a Statement of Overriding Considerations pursuant to CEQA Guidelines Section 15093, and a Mitigation, Monitoring and Reporting Plan pursuant to Public Resources Code Section 21081.6 and CEQA Guidelines Section 15097 were also prepared (see Attachment J of this board package – which is Attachment 1 to the Resolution).

Socioeconomic Analysis
PR 1109.1 will affect 16 facilities, including five major petroleum refineries representing nine individual facilities, three small refineries, and four facilities with related operations. The three small refineries consist of two asphalt refineries and one biodiesel refinery, and the four facilities with related operations include three hydrogen plants and one sulfuric acid plant. All 16 affected facilities are located in Los Angeles County.

Total compliance costs for facilities include equipment acquisition and installation fees, administrative fees (one-time and annual permitting fees) as well as potential cost-savings to facilities due to reduced annual emissions fees. Total costs are expected to range from $2.3 billion to $2.9 billion based on four percent and one percent discount rates, respectively, to convert costs occurring in different years to the same base year value. When annualized, the average total costs of PR 1109.1 are expected to range from $98.1 million to $132.4 million per year.

When the compliance cost is annualized using a four percent discount rate, it is projected that an average of 213 jobs could be created annually from 2022 to 2057. Despite incurring the majority of the total compliance cost, the petroleum and coal products manufacturing industry is projected to experience only minor impacts in terms of jobs forgone (14 annually, on average). This is due to the fact that the industry is capital-intensive (requires relatively large expenditures on physical assets such as buildings, equipment, and raw materials). The majority of the job gains are concentrated in the construction sector and result from the increased demand for control equipment installation.

Additionally, the average annual increase in fuel prices due to PR1109.1 is projected to be less than one cent per gallon, based on an analysis conducted by South Coast AQMD consultant Dr. Erich Muehlegger with the University of California – Davis.

The reductions in ozone and PM2.5 associated with the proposed rule are expected to reduce South Coast AQMD residents' mortality and morbidity risk through the control of NOx, a precursor pollutant. The public health benefits analysis is based on the conservative estimate of seven tpd NOx reductions, the benefits of which would be offset to a limited degree by a 0.63 tpd increase in ammonia emissions. In total, PR 1109.1 would result in approximately 370 premature fatalities avoided, 6,200 fewer asthma attacks and nearly 21,400 fewer work loss days from 2023-2037. The associated total monetized public health benefits over the same time period are projected to be $3.5 billion using a one percent discount rate and $2.6 billion using a four percent discount rate.

AQMP and Legal Mandates

PR 1109.1, PR 429.1, PAR 1304, PAR 2005 partially implement 2016 AQMP Control Measure CMB-05 which addresses the transition of NOx RECLAIM facilities to a command-and-control regulatory structure. These rules implement Sections 110, 172, 173, and 182(e) of the Clean Air Act and will be submitted to the CARB and U. S. EPA for inclusion into the State Implementation Plan. These rules also implement AB 617 BARCT requirements for the facilities subject to the rules.

Implementation and Resource Impacts

Staff estimates that approximately 278 new and additional permit applications are expected to be submitted over the next 10 years due to the implementation of

PR 1109.1. In addition, staff expects to receive six I-Plans, four B-Plans, and a B-Cap for review and approval. Almost half of those permits and all the plans are expected to be submitted within the first two years of implementation. Conservatively assuming that the new workload will be evenly distributed over 10 years, and the current workloads and production are maintained, implementation of PR 1109.1 would require at least one additional full time Air Quality Engineer, which will be requested in the next budget.

Attachments

A. Summary of Proposal – PR 1109.1
B. Summary of Proposal – PR 429.1
C. Summary of Proposal – PAR 1304 and PAR 2005
D. Key Issues and Responses
E. Rule Development Process – PR 1109.1
F. Rule Development Process – PR 429.1
G. Rule Development Process – PAR 1304 and PAR 2005
H. Key Contacts List
I. Resolution
J. Overriding Considerations and Mitigation, Monitoring, and Reporting Plan
K. Proposed Rule 1109.1
L. Proposed Rule 1109.1 Baseline NOx Emissions and Representative NOx Concentrations for Facilities Regulated Under Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations
M. Proposed Rule 429.1
N. Proposed Amended Rule 1304
O. Proposed Amended Rule 2005
P. Proposed Rescinded Rule 1109
Q. Final Staff Report for PR 1109.1 and PRR 1109
R. Final Staff Report for PR 429.1
S. Final Staff Report for PAR 1304 and PAR 2005
T. Final Socioeconomic Impact Assessment
U. Final Subsequent Environmental Assessment
V. Board Meeting Presentation

ATTACHMENT A

SUMMARY OF PROPOSED RULE 1109.1

Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations

Applicability

- Applies to owners and operators of facilities with units at petroleum refineries and facilities with related operations to petroleum refineries
- Applicable units include Boilers, Flares, FCCUs, Gas Turbines, Petroleum Coke Calciners, Process Heaters, SMR Heaters, Sulfuric Acid Furnaces, SRU/TG Incinerators, or Vapor Incinerators

Concentration Limits

- Establishes BARCT NOx and CO concentration limits for each class and category of equipment within a compliance schedule in Table 1
- Provides Conditional NOx and CO concentration limits for units that meet specific criteria or units that staff identified as having a high-cost effectiveness in Table 2

Interim Concentration Limits

- Establishes interim NOx Concentration Limits when facilities transition out of RECLAIM and before meeting the NOx concentration limits to ensure there is no backsliding
  - The approach to meet the interim limit is different for B-Plan and B-Cap

Compliance Schedule

- Operators must submit permit applications
  - July 1, 2023 when complying with Table 1 concentration limits, and meet NOx concentration limit 36 months after the Permit to Construct is issued
  - June 1, 2022 if eligible to comply with Table 2 concentration limits, and meet NOx concentration limit 18 months after the Permit to Construct is issued
- Operators with six or more units have the option to submit an I-Plan either to meet the Table 1 and Table 2 NOx concentration limits or implement an alternative BARCT plan, in lieu of submitting permits by July 1, 2023 (see B-Plan, B-Cap, and I-Plan below)

Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations

B-Plan and B-Cap Requirements

- Includes two BARCT alternative compliance options for facilities with six or more units to achieve the same emission reductions as meeting Table 1 and Table 2 NOx concentration limits
  - B-Plan: Facilities meet the Table 1 and Table 2 NOx concentration limits in aggregate using Alternative NOx Concentration Limits; and
  - B-Cap: Facilities meet the Table 1 and Table 2 limits based on aggregate mass emissions
    - Units complying in a B-Cap will have a maximum alternative BARCT NOx concentration limit and a daily requirement to demonstrate facility-wide emissions are below mass emissions cap
    - 10% environmental benefit required
- The alternative plan should be submitted on or before September 1, 2022 and permit applications should be submitted based on the schedule in the approved I-Plan
- At full implementation, all units will have an enforceable NOx concentration permit limit

I-Plan Requirements

- I-Plan provides an alternative implementation schedule for facilities complying with a B-Plan, B-Cap, or Table 1 and Table 2 NOx concentration limits.
  - Five different I-Plan options are included in Table 6 with different implementation schedules and emission reduction targets
  - Facility BARCT Emission Target for each phase and the final phase shall be calculated based on Attachment B of the rule

I-Plan, B-Plan, and B-Cap Submittal and Approval Requirements

- I-Plan, B-Plan, and B-Cap must be submitted on or before September 1, 2022
- Specific requirements of information to be included in each of the plans
- Specific criteria for evaluating and reviewing each of the plans
- I-Plan, B-Plan, and B-Cap will be approved if applicable criteria are met and not approved if the applicable criteria are not met
- Resubmit I-Plan, B-Plan, or B-Cap within 45 days of receiving disapproval
- Executive Officer will make the proposed plans or modifications to approved plans available to the public at least 30 days prior to approval

Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations

Time Extensions

- 12-Month time extension to demonstrate compliance if delay in installation due to circumstances outside control of the owner or operator
- Time extension to accommodate the scheduled turnaround for a Unit if permit issuance is longer than18 months
- Time extensions to meet NOx concentration limit and lowering of the mass emissions cap under the B-Cap

Emission Testing Requirements

- Units greater than 40 MMBtu/hour will have to maintain and certify Continuous Emission Monitoring Systems (CEMS)
- Source testing requirements and diagnostic emission checks for units less than 40 MMBtu/hour

Monitoring, Recordkeeping, and Reporting Requirements

- For each Unit, a daily record of time and duration of startup and shutdown events, total hours of operation, fuel usage, and cumulative hours of operation to date for the calendar year should be maintained
- For a facility complying with a B-Cap, reporting on the NOx mass emissions monthly

Exemptions

- Provisions regarding specific Units exempt from compliance with NOx and CO emission limits including because Units are low-use or very small:
    - Boilers and process heaters less than 2 MMBtu/hour, low-use boilers and process heaters based on sizing above or below 40 MMBtu/hour, FCCU startup boilers and process heaters, startup or shutdown boilers and process heaters at sulfuric acid plants, flares, vapor incinerators, etc.

ATTACHMENT B

SUMMARY OF PROPOSED RULE 429.1

Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations
<u>Applicability</u> • Units at petroleum refineries and facilities with related operations to petroleum refineries <u>Exemption from Proposed Rule 1109.1 Emission</u> Limits • Establishes exemption from Proposed Rule 1109.1 NOx and CO concentration limits during startup, shutdown, commissioning, and certain maintenance events <u>Startup and Shutdown Limits</u> • Limits duration of time that an operator is exempt from NOx and CO concentration limits for startup and shutdown events • Limits frequency of scheduled startups <u>Requirements for Units with NOx Post-Combustion Control Equipment</u> • Operate NOx post-combustion control equipment when exhaust gas temperature reaches temperature and the unit stabilizes • Install and maintain an annually calibrated temperature measuring device <u>Catalyst Maintenance Requirements</u> • Limited to units equipped with a bypass stack or duct by [*Date of Adoption*] and units that are scheduled to operate continuously for 5 years or more between turnarounds • Hour limitation to conduct catalyst maintenance while using a bypass stack or duct • Requires operation at ≤ 50% of the feed rate of the process unit <u>Notification and Recordkeeping Requirements</u> • Notification for scheduled startups and catalyst maintenance • Maintain operating log, list of scheduled startups, list of planned maintenance shutdowns, NOx and CO emissions data during catalyst maintenance, and records of the minimum operating temperature of NOx post-combustion control equipment <u>Exemptions</u> • Exemptions for refractory dryout, catalyst regeneration activities, commissioning, water freeing, and when fuel is only used for the pilot light • Exemption for units with existing permit conditions for units with a bypass to conduct maintenance

ATTACHMENT C

SUMMARY OF PROPOSED AMENDED RULE 1304 AND PROPOSED AMENDED RULE 2005

Proposed Amended Rule 1304 – Exemptions

Limited BACT Exemption
• Narrow BACT exemption for PM_{10} and/or SOx emission increases
  o Emission increases must be associated with add-on air pollution control equipment needed to comply with a command-and-control NOx BARCT limit
  o NOx BARCT limit must have been initially established before December 31, 2023 as part of the RECLAIM transition
  o BACT exemption will be limited to projects that:
    ▪ Do not increase the cumulative total maximum rated capacity
    ▪ Serve the same purpose as those being replaced or modified
    ▪ Do not increase the physical or operational design capacity for the facility
    ▪ Do not cause an exceedance of any state or national ambient air quality standard
    ▪ Do not trigger federal major New Source Review

Proposed Amended Rule 2005 – New Source Review for RECLAIM

Requirements for Existing RECLAIM Facilities, Modification to New RECLAIM Facilities, Facilities which Undergo a Change of Operator, or Facilities which Increase an Annual Allocation to a Level Greater Than the Facility's Starting Allocation Plus Non-Tradable Credits
• Allows a RECLAIM facility to meet the BACT requirement under Regulation XIII in lieu of Rule 2005
  o Only applicable for SOx emission increases associated with basic equipment replacements that are combined with the installation or modification of add-on air pollution control equipment
  o Limited to control equipment exclusively installed to comply with a Regulation XI rule
• RECLAIM facilities that elect to meet the Regulation XIII BACT requirement can use the proposed BACT exemption in PAR 1304, if the new or modified source meets the criteria specified in PAR 1304

ATTACHMENT D

KEY ISSUES AND RESPONSES

Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations
Throughout the rulemaking process, staff worked with stakeholders to address and resolve a number of key issues. Notable issues that were resolved through the rulemaking process were: • Agreeing that RTCs would not be used to meet PR 1109.1 interim provisions, • Incorporating revised facility cost estimates into the cost-effectiveness analysis, • Incorporating the incremental cost-effectiveness prior to establishing a proposed BARCT limit, • Developing an exemption for co-pollutant emissions for SCR systems used to meet PR 1109.1 NOx limits, • Incorporating a ten percent environmental benefit in the B-Cap, and • Incorporating compliance flexibility without forgoing NOx reductions. Key Remaining Issue: Environmental and community groups commented that PR 1109.1 is not consistent with AB 617 which requires "implementation of best available retrofit control technology (BARCT), by the earliest feasible date, but in any event not later than December 31, 2023." Staff Response: • PR 1109.1 implements expedited BARCT in accordance with AB617 by December 31, 2023 while delivering additional NOx emission reductions representative of BARCT beyond 2023 • Staff estimates that 3.7 to 3.8 tons per day of NOx emission reductions, or 50 percent of the overall rule reductions, will be achieved by December 31, 2023 • PR 1109.1 goes beyond AB 617 by establishing lower NOx limits to achieve additional NOx reductions beyond December 31, 2023   o PR 1109.1 will achieve an additional 4.0 to 4.1 tons per day of NOx emission reductions beyond December 31, 2023, which provides an overall NOx reduction of 7.7 to 7.9 tons per day

ATTACHMENT E

RULE DEVELOPMENT PROCESS

Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen From Petroleum Refineries and Related Operations

Initiated Rule Development
February 2018

⬇

Working Group Meetings (25)
February 21,2018; June 14, 2018; August 1, 2018; September 12, 2018; November 28, 2018; January 31, 2019; April 30, 2019; June 27, 2019; December 12, 2019; February 18, 2020; May 21, 2020; July 17, 2020; August 12, 2020; August 27, 2020; November 4, 2020; December 10, 2020; February 4, 2021; February 11, 2021; March 4, 2021; April 30, 2021; May 27, 2021; June 30, 2021; July 14, 2021; July 28, 2021; September 15, 2021

⬇

Stationary Source Committee Meetings (5)
September 15, 2021; February 19, 2021; March 19, 2021; June 18, 2021; September 17, 2021

⬇

75-Day Notice of Public Workshop
August 20, 2021

⬇

Public Workshop
September 1, 2021

⬇

Study Session
September 10, 2021

⬇

30-Day Notice of Public Hearing
September 21, 2021

⬇

Set Public Hearing
October 1, 2021

⬇

Community Meeting
October 26, 2021

⬇

Public Hearing
November 5, 2021

Forty-six (46) months for rule development.

One (1) Public Workshop.

One (1) Study Session.

Five (5) Stationary Source Committee Meetings.

Twenty-Five (25) Working Group Meetings – one held virtually in the community.

One (1) Community Presentation.

ATTACHMENT F

RULE DEVELOPMENT PROCESS

Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations

Initiated Rule Development
October 2020

⬇

Working Group Meetings Under PR 1109.1 (3)
November 4, 2020, December 10, 2020, and February 4, 2021

⬇

PR 1109.1 and PR 429.1 Bifurcated
February 2021

⬇

Working Group Meetings for PR 1109.1/PR 429.1 (2)
April 30, 2021 and May 27, 2021

⬇

75-Day Notice of Public Workshop
August 20, 2021

⬇

Public Workshop
September 1, 2021

⬇

Study Session for PR 1109.1/PR 429.1/PAR 1304/PAR 2005
September 10, 2021

⬇

Working Group Meeting for PR 1109.1/PR 429.1/PAR 1304/PAR 2005
September 15, 2021

⬇

Stationary Source Committee Meeting
September 17, 2021

⬇

30-Day Notice of Public Hearing
September 21, 2021

⬇

Set Public Hearing
October 1, 2021

⬇

Public Hearing
November 5, 2021

Thirteen (13) months spent in rule development
One (1) Public Workshop
One (1) Study Session
One (1) Stationary Source Committee Meeting
Six (6) Working Group Meetings

ATTACHMENT G

RULE DEVELOPMENT PROCESS

Proposed Amended Rule 1304 – Exemptions and Proposed Amended Rule 2005 – New Source Review for RECLAIM

Initiated Rule Development
July 2020

⬇

Working Group Meetings Under PR 1109.1 (5)
July 17, 2020; August 12, 2020; February 4, 2021;
March 4, 2021; May 27, 2021

⬇

Working Group Meetings Under Regulation XIII (5)
January 21, 2021; February 18, 2021; April 15, 2021;
May 13, 2021; June 16, 2021

⬇

75-Day Notice of Public Workshop
August 20, 2021

⬇

Public Workshop
September 1, 2021

⬇

Study Session for PR 1109.1/PR 429.1/PAR 1304/PAR 2005
September 10, 2021

⬇

Working Group Meeting for PR 1109.1/PR 429.1/PAR 1304/PAR 2005
September 15, 2021

⬇

Stationary Source Committee Meeting
September 17, 2021

⬇

30-Day Notice of Public Hearing
September 21, 2021

⬇

Set Public Hearing
October 1, 2021

⬇

Public Hearing
November 5, 2021

Sixteen (16) months spent in rule development
One (1) Public Workshop
One (1) Study Session
One (1) Stationary Source Committee Meeting
Eleven (11) Working Group Meetings

ATTACHMENT H
KEY CONTACTS LIST

Air Liquide Large Industries U.S., LP
Air Products and Chemical, Inc.
AltAir Paramount
Babcock Power Environmental
Bay Area Air Quality Management District
Bay City Boilers
Benz Air Engineering Co
California Air Resources Board
California Communities Against Toxics
California Council for Environmental and Economic Balance
Callidus® Technologies Honeywell UOP
Center for Biological Diversity
Chevron Products Co.
ClearSign Combustion Corporation
Coalition for Clean Air
Communities for a Better Environment
Community Environmental Services
Cormetech
Dupont Clean Technologies
Earthjustice
East Yard Communities
Eco-Services Operations, LLC
Environmental Management Professionals
Fossil Energy Research Corporation
George T. Hall Company
Great Southern Flameless
Honeywell UOP
John Zink Hamworthy Combustion
Latham and Watkins
Lunday-Thagard Co. DBA World Oil Refining
Marathon Petroleum Corporation
Natural Resources Defense Council
Northwest Clean Air Agency
Norton Engineering Consultant's
Peerless CECO Environmental
Phillips 66 Company
Ramboll
Regulatory Flexibility Group
Shasta County Air Quality Management District
Sierra Club
Southern California Air Quality Alliance
Torrance Refining Company, LLC
Tri-Mer Corporation
Western States Petroleum Association
Ultramar Inc.
Umicore Catalysis USA, LLC
U.S. Environmental Protection Agency
ZEECO, Inc.

ATTACHMENT I

RESOLUTION NO. 21-_____

A Resolution of the South Coast Air Quality Management District (South Coast AQMD) Governing Board certifying the Final Subsequent Environmental Assessment for Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (Proposed Rule 1109.1), Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations (Proposed Rule 429.1), Proposed Amended Rule 1304 – Exemptions (Proposed Amended Rule 1304), Proposed Amended Rule 2005 – New Source Review for RECLAIM (Proposed Amended Rule 2005), and Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries (Proposed Rescinded Rule 1109).

A Resolution of the South Coast AQMD Governing Board adopting Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations and Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations, amending Rule 1304 – Exemptions and Rule 2005 – New Source Review for RECLAIM, and rescinding Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries.

WHEREAS, the South Coast AQMD Governing Board finds and determines that Proposed Rule 1109.1, Proposed Rule 429.1, Proposed Amended Rule 1304, Proposed Amended Rule 2005, and Proposed Rescinded Rule 1109 are considered a "project" as defined by the California Environmental Quality Act (CEQA); and

WHEREAS, the South Coast AQMD has had its regulatory program certified pursuant to Public Resources Code Section 21080.5 and CEQA Guidelines Section 15251(l), and has conducted a CEQA review and analysis of the proposed project pursuant to such program (South Coast AQMD Rule 110); and

WHEREAS, the South Coast AQMD Governing Board has determined that the requirements for a Subsequent Environmental Impact Report have been triggered pursuant to its certified regulatory program and CEQA Guidelines Section 15162(b), and that a Subsequent Environmental Assessment (SEA), a substitute document allowed pursuant CEQA Guidelines Section 15252 and South Coast AQMD's certified regulatory program, is appropriate; and

WHEREAS, the South Coast AQMD has prepared a SEA pursuant to its certified regulatory program and CEQA Guidelines Section 15187, which tiers off of the December 2015 Final Program Environmental Assessment (PEA) for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM) (referred to as NOx RECLAIM) and the March 2017 Final Program Environmental Impact Report (EIR) for the 2016 Air Quality Management Plan (AQMP) as allowed by CEQA Guidelines Sections 15152, 15162, 15168, and 15385. Because the SEA is a subsequent document to the December 2015 Final PEA for NOx RECLAIM, the baseline is the project analyzed in the December 2015 Final PEA for NOx RECLAIM. The SEA, in setting forth the potential environmental consequences of the proposed project, determined that substantial increases in the severity of the significant effects that were previously examined in the December 2015 Final PEA for NOx RECLAIM would occur. [CEQA Guidelines Section 15162(a)(3)(B)]. The SEA concluded that the proposed project would have the potential to generate significant adverse environmental impacts for the topics of air quality during construction and greenhouse gas emissions, hazards and hazardous materials associated with ammonia, and hydrology (water demand), after mitigation measures are applied; and

WHEREAS, the Draft SEA was circulated for a 46-day public review and comment period from September 3, 2021 to October 19, 2021 and six comment letters were received; and

WHEREAS, the Draft SEA has been revised to include the comment letters received on the Draft SEA and the responses, so that it is now a Final SEA; and

WHEREAS, it is necessary that the South Coast AQMD Governing Board review the Final SEA prior to its certification, to determine that it provides adequate information on the potential adverse environmental impacts that may occur as a result of adopting Rule 1109.1 and Rule 429.1, amending Rule 1304 and Rule 2005, and rescinding Rule 1109, including the responses to the comment letters received relative to the Draft SEA; and

WHEREAS, pursuant to CEQA Guidelines Section 15252(a)(2)(A), significant adverse impacts were identified such that alternatives and mitigation measures are required for project approval; thus, a Mitigation Monitoring and Reporting Plan pursuant to Public Resources Code Section 21081.6 and CEQA Guidelines Section 15097, has been prepared; and

WHEREAS, no feasible mitigation measures were identified that would reduce or eliminate the significant adverse impacts to less than significant levels; and,

WHEREAS, it is necessary that the South Coast AQMD prepare Findings pursuant to CEQA Guidelines Section 15091, and a Statement of Overriding Considerations pursuant to CEQA Guidelines Section 15093, regarding potentially significant adverse environmental impacts that cannot be mitigated to less than significant levels; and

WHEREAS, Findings, a Statement of Overriding Considerations, and a Mitigation, Monitoring, and Reporting Plan have been prepared and are included in Attachment 1 to this Resolution (labeled as Attachment J in the Board letter), which is attached and incorporated herein by reference; and

WHEREAS, the South Coast AQMD Governing Board voting to adopt Proposed Rule 1109.1 and Proposed Rule 429.1, amend Rule 1304 and Rule 2005, and rescind Rule 1109, has reviewed and considered the information contained in the Final SEA, including responses to comments, the Mitigation, Monitoring, and Reporting Plan, the Findings, the Statement of Overriding Considerations, and all other supporting documentation, prior to its certification, and has determined that the Final SEA, including responses to comments received, has been completed in compliance with CEQA; and

WHEREAS, Proposed Rule 1109.1, Proposed Rule 429.1, Proposed Amended Rule 1304, Proposed Amended Rule 2005, and Proposed Rescinded Rule 1109 and supporting documentation, including but not limited to, the Final SEA, the Final Socioeconomic Impact Assessment, and the Final Staff Reports were presented to the South Coast AQMD Governing Board and the South Coast AQMD Governing Board has reviewed and considered this information, as well as has taken and considered staff testimony and public comment prior to approving the project; and

WHEREAS, the Final SEA reflects the independent judgment of the South Coast AQMD; and

WHEREAS, the South Coast AQMD Governing Board finds and determines that all changes made in the Final SEA after the public notice of availability of the Draft SEA, were not substantial revisions and do not constitute significant new information within the meaning of CEQA Guidelines Sections 15073.5 and 15088.5, because no new or substantially increased significant effects were identified, and no new project conditions or mitigation measures were added, and all changes merely clarify, amplify, or make insignificant modifications to the Draft SEA, and recirculation is therefore not required; and

WHEREAS, the South Coast AQMD Governing Board finds and determines, taking into consideration the factors in Section (d)(4)(D) of the Governing Board Procedures (Section 30.5(4)(D)(i) of the Administrative Code), that the modifications to Proposed Rule 1109.1 since the Notice of Public Hearing was published are clarifications that meets the same air quality objective and is not so substantial as to significantly affect the meaning of Proposed Rule 1109.1 within the meaning of Health and Safety Code Section 40726 because the changes to subparagraph (e)(2)(A) and subparagraph (m)(1)(C) are to clarify rule language, changes to paragraph (e)(3), clause (g)(1)(B)(iii), paragraph (o)(7), and Attachment B are to correct rule references, the addition to subparagraph (g)(3)(B) is to clarify that small vapor incinerators can be excluded from a B-Cap, the change to subparagraph (h)(4)(B) is to correct a table name, the change to paragraph (l)(6) is to allow written notifications of source test schedules, change to Attachment C is to reflect a correction in the facility baseline, and the changes to Attachment D are to correct eligible units and clarify table names and: (a) the changes does not impact emission reductions, (b) the changes does not affect the number or type of sources regulated by the rule, (c) the changes are not inconsistent with the information contained in the Notice of Public Hearing, and (d) the effects of Proposed Rule 1109.1 do not exceed the effects of the range of alternatives analyzed in the CEQA document; and

WHEREAS, the South Coast AQMD Governing Board finds and determines, taking into consideration the factors in Section (d)(4)(D) of the Governing Board Procedures (Section 30.5(4)(D)(i) of the Administrative Code), that the modifications to Proposed Rule 429.1 since the Notice of Public Hearing was published are clarifications that meet the same air quality objective and are not so substantial as to significantly affect the meaning of Proposed Rule 429.1 within the meaning of Health and Safety Code Section 40726 because the changes to paragraph (c)(7) and subparagraph (d)(7)(C) and deletion of former paragraph (c)(13) are made to correct terminology, the changes to subdivision (a), paragraph (d)(1), paragraph (d)(2) are made to clarify rule language, and the change to paragraph (d)(1) is made to correct rule references and: (a) the changes do not impact emission reductions, (b) the changes do not affect the number or type of sources regulated by the rule, (c) the changes are consistent with the information contained in the Notice of Public Hearing, and (d) the effects of Proposed Rule 429.1 do not exceed the effects of the range of alternatives analyzed in the CEQA document; and

WHEREAS, the South Coast AQMD Governing Board finds and determines, taking into consideration the factors in Section (d)(4)(D) of the Governing Board Procedures (Section 30.5(4)(D)(i) of the Administrative Code), that there were no modifications to Proposed Amended Rule 1304 or Proposed Amended Rule 2005 since the Notice of Public Hearing was published; and

WHEREAS, Proposed Rule 1109.1, Proposed Rule 429.1, Proposed Amended Rule 1304, and Proposed Amended Rule 2005 will be submitted for inclusion into the State Implementation Plan; and

WHEREAS Rule 1109 is not in the State Implementation Plan, and the rule's rescission will not require any update to the State Implementation Plan; and

WHEREAS, the South Coast AQMD staff conducted a Public Workshop on September 1, 2021 regarding Proposed Rule 1109.1, Proposed Rule 429.1, Proposed Amended Rule 1304, Proposed Amended Rule 2005, and Proposed Rescinded Rule 1109; and

WHEREAS, Health and Safety Code Section 40727 requires that prior to adopting, amending or repealing a rule or regulation, the South Coast AQMD Governing Board shall make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the public hearing and in the Final Staff Report; and

WHEREAS, the South Coast AQMD Governing Board has determined that Proposed Rule 1109.1, Proposed Rule 429.1, Proposed Amended Rule 1304, Proposed Amended Rule 2005, and Proposed Rescinded Rule 1109 are needed to continue with the transition of facilities in the RECLAIM program to a command-and-control regulatory structure by setting BARCT and transition schedule to meet the commitments of Control Measure CMB-05 of the Final 2016 Air Quality Management Plan and to implement the requirements of AB 617 for facilities covered by Rule 1109.1; and

WHEREAS, the South Coast AQMD Governing Board obtains its authority to adopt, amend or repeal rules and regulations from Sections 39002, 40000, 40001, 40440, 40441, 40702, 40725 through 40728, and 41508 of the Health and Safety Code; and

WHEREAS, the South Coast AQMD Governing Board has determined that Proposed Rule 1109.1, Proposed Rule 429.1, Proposed Amended Rule 1304, and Proposed Amended Rule 2005 are written and displayed so that its meaning can be easily understood by persons directly affected by it; and

WHEREAS, the South Coast AQMD Governing Board has determined that Proposed Rule 1109.1, Proposed Rule 429.1, Proposed Amended Rule 1304, and Proposed Amended Rule 2005 are in harmony with and not in conflict with, or contradictory to, existing statutes, court decisions, or state or federal regulations; and

WHEREAS, the South Coast AQMD Governing Board has determined that Proposed Rule 1109.1, Proposed Rule 429.1, Proposed Amended Rule 1304, and Proposed Amended Rule 2005 do not impose the same requirements as any existing state or federal regulations, and the proposed project is necessary and proper to execute the powers and duties granted to, and imposed upon, the South Coast AQMD; and

WHEREAS, the South Coast AQMD Governing Board, in adopting Rule 1109.1 and Rule 429.1, amending Rule 1304 and Rule 2005, and rescinding Rule 1109, references the following statutes which the South Coast AQMD hereby implements, interprets or makes specific: Assembly Bill 617, Health and Safety Code Sections 39002, 39616, 40001,40406, 40702, 40440(a), 40725 through 40728.5, 42300 et seq., and Clean Air Act Sections 110, 172, 173 and 182(e); and

WHEREAS, Health and Safety Code Section 40727.2 requires the South Coast AQMD to prepare a written analysis of existing federal air pollution control requirements applicable to the same source type being regulated whenever it adopts, or amends a rule, and that the South Coast AQMD's comparative analyses of Proposed Rule 1109.1, Proposed Rule 429.1, Proposed Amended Rule 1304, and Proposed Amended Rule 2005 are included in their respective Final Staff Reports; and

WHEREAS, the South Coast AQMD Governing Board has determined that the Final Socioeconomic Impact Assessment for Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations, Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations, Proposed Amended Rule 1304 – Exemptions, and Proposed Amended Rule 2005 – New Source Review for RECLAIM is consistent with the March 17, 1989 Governing Board Socioeconomic Resolution for rule adoption; and

WHEREAS, the South Coast AQMD Governing Board has determined that the Final Socioeconomic Impact Assessment for Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations, Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations, Proposed Amended Rule 1304 – Exemptions, and Proposed Amended Rule 2005 – New Source Review for RECLAIM is consistent with the provisions of Health and Safety Code Sections 40440.8 and 40728.5, and 40920.6; and

WHEREAS, the South Coast AQMD Governing Board finds that staff's proposed control options for Proposed Rule 1109.1 are being adopted because they constitute BARCT, as required by AB 617, and that the other control options did not meet BARCT; and

WHEREAS, the South Coast AQMD Governing Board has determined that Proposed Rule 1109.1 will result in increased costs to affected industries, yet are considered to be reasonable, with a total annualized cost as specified in the Final Socioeconomic Impact Assessment; and

WHEREAS, the South Coast AQMD Governing Board has actively considered the Final Socioeconomic Impact Assessment and has made a good faith effort to minimize such impacts; and

WHEREAS, a public hearing has been properly noticed in accordance with all provisions of Health and Safety Code Sections 40725 and 40440.5; and

WHEREAS, the South Coast AQMD Governing Board has held a public hearing in accordance with all provisions of state and federal law; and

WHEREAS, the South Coast AQMD Governing Board specifies that the Assistant Deputy Executive Officer for Planning and Rules overseeing the rule development for Proposed Rule 1109.1, Proposed Rule 429.1, Proposed Amended Rule 1304, Proposed Amended Rule 2005, and Proposed Rescinded Rule 1109 as the custodian of the documents or other materials which constitute the record of proceedings upon which the adoption of this proposed project is based, which are located at the South Coast Air Quality Management District, 21865 Copley Drive, Diamond Bar, California; and

NOW, THEREFORE BE IT RESOLVED, that the South Coast AQMD Governing Board has considered the Final SEA for Proposed Rule 1109.1, Proposed Rule 429.1, Proposed Amended Rule 1304, Proposed Amended Rule 2005, and Proposed Rescinded Rule 1109, together with all comments received during the public review period, and, on the basis of the whole record before it, the South Coast AQMD Governing Board: 1) finds that the Final SEA, including the responses to the comment letters, was completed in compliance with CEQA and the South Coast AQMD's certified regulatory program, 2) finds that the Final SEA and all supporting documents were presented to the South Coast AQMD Governing Board, whose members exercised their independent judgment and reviewed, considered, and approved the information therein prior to acting on Proposed Rule 1109.1, Proposed Rule 429.1, Proposed Amended Rule 1304, Proposed Amended Rule 2005, and Proposed Rescinded Rule 1109, and 3) certifies the Final SEA; and

BE IT FURTHER RESOLVED, that the South Coast AQMD Governing Board does hereby adopt Findings pursuant to CEQA Guidelines Section 15091, a Statement of Overriding Considerations pursuant to CEQA Guidelines Section 15093, and a Mitigation, Monitoring, and Reporting Plan pursuant to Public Resources Code Section 21081.6 and CEQA Guidelines Section 15097, as required by CEQA and which are included as Attachment J (Attachment 1 to the Resolution) and incorporated herein by reference; and

BE IT FURTHER RESOLVED, that the South Coast AQMD Governing Board directs staff to report on the status of the emerging technologies in 2029 and conduct a technology assessment if these technologies are not being commercialized; and

BE IT FURTHER RESOLVED, that the South Coast AQMD Governing Board does hereby, pursuant to the authority granted by law, adopt Rule 1109.1 and Rule 429.1, amend Rule 1304 and Rule 2005, and rescind Rule 1109 as set forth in the attached, and incorporated herein by reference; and

BE IT FURTHER RESOLVED, that the South Coast AQMD Governing Board requests that Proposed Rule 1109.1, Proposed Rule 429.1, Proposed Amended Rule 1304, and Proposed Amended Rule 2005 be submitted into the State Implementation Plan; and

BE IT FURTHER RESOLVED, that the Executive Officer is hereby directed to forward a copy of this Resolution and Proposed Rule 1109.1, Proposed Rule 429.1, Proposed Amended Rule 1304, and Proposed Amended Rule 2005 to the California Air Resources Board for approval and subsequent submittal to the U.S. Environmental Protection Agency for inclusion into the State Implementation Plan.

DATE: ________________ ______________________

CLERK OF THE BOARDS

ATTACHMENT J

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Attachment 1 to the Governing Board Resolution for:

Final Subsequent Environmental Assessment for Proposed Rule 1109.1 - Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Industries, Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations, Proposed Amended Rule 1304 – Exemptions, Proposed Amended Rule 2005 – New Source Review for RECLAIM, and Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries

Findings, Statement of Overriding Considerations, and Mitigation, Monitoring, and Reporting Plan

October 2021

State Clearinghouse No. 2014121018
South Coast AQMD No. 20210901KN

Executive Officer
Wayne Nastri

Deputy Executive Officer
Planning, Rule Development and Area Sources
Sarah Rees, Ph.D.

Assistant Deputy Executive Officer
Planning, Rule Development and Area Sources
Susan Nakamura

Assistant Deputy Executive Officer
Planning, Rule Development and Area Sources
Ian MacMillan

Author:	Kevin Ni	Air Quality Specialist
Reviewed By:	Barbara Radlein	Program Supervisor, CEQA
	Michael Krause	Planning and Rules Manager
	Barbara Baird	Chief Deputy Counsel
	Veera Tyagi	Principal Deputy District Counsel
	William Wong	Principal Deputy District Counsel

TABLE OF CONTENTS

Attachment 1 to the Governing Board Resolution for:
Final Subsequent Environmental Assessment for Proposed Rule 1109.1 - Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Industries, Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations, Proposed Amended Rule 1304 – Exemptions, Proposed Amended Rule 2005 – New Source Review for RECLAIM, and Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries

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Findings, Statement of Overriding Considerations, and Mitigation, Monitoring, and Reporting Plan

1.0 Introduction

Proposed Rules (PRs) 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations and 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations, Proposed Amended Rules (PARs) 1304 – Exemptions and 2005 – New Source Review for RECLAIM, and the proposed rescission of Rule 1109 are considered a "project" as defined by the California Environmental Quality Act (CEQA) [Public Resources Code Section 21000 et seq.]. Specifically, CEQA requires: 1) the potential adverse environmental impacts of proposed projects to be evaluated; and 2) feasible methods to reduce or avoid any identified significant adverse environmental impacts of these projects to also be evaluated. CEQA Guidelines Section 15364 defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors."

Since the proposed project is comprised of South Coast AQMD-proposed rules, proposed amended rules, and one proposed rescinded rule, the South Coast AQMD has the greatest responsibility for carrying out or approving the project as a whole, which may have a significant effect upon the environment, and is the most appropriate public agency to act as lead agency. [Public Resources Code Section 21067 and CEQA Guidelines Section 15051(b)].[1]

The proposed project amends the previous Best Available Retrofit Control Technology (BARCT assessments) conducted for: 1) facilities in the refinery sector that emit nitrogen oxides (NOx) as previously analyzed in the Final Program Environmental Assessment (PEA) for Proposed Amended Regulation XX – Regional Clean Air Incentives Market which was certified on December 4, 2015 (referred to herein as the December 2015 Final PEA for NOx RECLAIM)[2]; and 2) Control Measure CMB-05 and the entire RECLAIM Transition project in the 2016 Air Quality Management Plan (AQMP) as previously analyzed in the Final Program Environmental Impact Report (EIR) for the 2016 Air Quality Management Plan (AQMP) which was certified on March 3, 2017 (referred to herein as the March 2017 Final Program EIR for the 2016 AQMP)[3].

The South Coast AQMD, as Lead Agency for the proposed project, prepared a Subsequent Environmental Assessment (SEA) with significant impacts to conduct an environmental review of new and amended rules and regulations pursuant to CEQA Guidelines Section 15187. The SEA is a substitute CEQA document prepared in lieu of a Subsequent Environmental Impact Report (EIR) with significant impacts [CEQA Guidelines Section 15162], to analyze environmental impacts for the proposed project pursuant to its certified regulatory program (Public Resources Code Section 21080.5, CEQA Guidelines Section 15251(l), and South Coast AQMD Rule 110). Pursuant to CEQA Guidelines Sections 15152, 15162, 15168, and 15385, the SEA tiers off of two programmatic CEQA documents: the December 2015 Final PEA for NOx RECLAIM and the March 2017 Final Program EIR for the 2016 AQMP.

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1 CEQA Guidelines refers to California Code of Regulations, Title 14, Section 15000 and following.

2 South Coast AQMD, Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), SCH No. 2014121018/SCAQMD No. 12052014BAR, certified December 4, 2015. http://www.aqmd.gov/home/library/documents-support-material/lead-agency-scaqmd-projects/scaqmd-projects---year-2015.

3 South Coast AQMD, Final Program Environmental Impact Report for the 2016 Air Quality Management Plan, SCH No, 2016071006, certified March 3, 2017. http://www.aqmd.gov/home/research/documents-reports/lead-agency-SCAQMD-projects/SCAQMD-projects---year-2017.

The SEA is a subsequent document to the December 2015 Final PEA for NOx RECLAIM. Because this is a subsequent document, the baseline is the project analyzed in the December 2015 Final PEA for NOx RECLAIM. The SEA was prepared because the proposed project is expected to substantially increase the severity of the significant effects that were previously examined in the December 2015 Final PEA for NOx RECLAIM [CEQA Guidelines Section 15162(a)(3)(B)].

The December 2015 Final PEA for NOx RECLAIM concluded that the topics of air quality during construction and greenhouse gases (GHGs), hazards and hazardous materials associated with ammonia, and hydrology would have significant adverse impacts and mitigation measures for air quality during construction, and hydrology were adopted. However, no feasible mitigation measures for avoiding or reducing hazards and hazardous materials impacts associated with ammonia were identified. For the significant adverse environmental impacts that were identified for the project analyzed in the December 2015 Final PEA for NOx RECLAIM and for which mitigation measures were incorporated, the analysis concluded that the December 2015 amendments to the NOx RECLAIM program would have significant and unavoidable adverse environmental impacts even after mitigation measures were applied. As such, mitigation measures were made a condition of approving the project analyzed in the December 2015 Final PEA for NOx RECLAIM and a Mitigation Monitoring Plan was adopted. Findings were made and a Statement of Overriding Considerations was adopted by the South Coast AQMD Governing Board. A copy of the Findings, Statement of Overriding Considerations, and Mitigation Monitoring Plan previously adopted for the December 2015 Final EA for NOx RECLAIM[4] is provided in Appendix A.

The SEA, which includes a project description and analysis of potential adverse environmental impacts that could be generated from the proposed project, concluded to have the same or similar significant effects that were previously examined in the December 2015 Final PEA for NOx RECLAIM but more severe than what was previously discussed. Specifically, the Final SEA concluded that significant and unavoidable adverse environmental impacts may occur for the following environmental topic areas: 1) air quality during construction and GHGs; 2) hazards and hazardous materials associated with ammonia; and 3) hydrology. Since the proposed project evaluated in the Final SEA would result in more severe significant adverse impacts than what were previously identified in the December 2015 Final PEA for NOx RECLAIM, an alternatives analysis and mitigation measures were required and have been included in the Final SEA. Essentially the same mitigation measures for air quality during construction and GHGs, and hydrology as adopted for the December 2015 Final PEA for NOx RECLAIM are included in the Final SEA but the wording has been updated for clarity and consistency with mitigation measures from other, more recently adopted South Coast AQMD rule development projects with similar environmental impacts. While no feasible mitigation measures for avoiding or reducing hazards and hazardous materials impacts associated with ammonia were identified at the time the December 2015 Final PEA for NOx RECLAIM was certified, feasible mitigation measures applicable to the use and storage of ammonia have been recently developed. Thus, the Final SEA contains new mitigation measures to address the hazards and hazardous materials impacts associated with the use and storage of ammonia.

[4] South Coast AQMD, Attachment 1 to the Governing Board Resolution: Findings, Statement of Overriding Considerations, and Mitigation Monitoring Plan for Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), SCH No. 2014121018/SCAQMD No. 12052014BAR, certified December 4, 2015. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2015/regxxfindings.pdf.

The Draft SEA was released and circulated for a 46-day public review and comment period from September 31, 2021 to October 19, 2021. Five comment letters were received during the comment period and one comment letter was received after the close of the comment period. None of the comment letters identified other potentially significant adverse impacts from the proposed project that should be analyzed and mitigated in the SEA. The comments and responses relative to the Draft SEA are included in Appendix F of the Final SEA.

In addition to incorporating the comment letters and the responses to comments, some modifications have been made to the Draft SEA to make it a Final SEA. South Coast AQMD staff evaluated the modifications made to the proposed project after the release of the Draft SEA for public review and comment and concluded that none of the revisions constitute significant new information, because: 1) no new significant environmental impacts would result from the proposed project; 2) there is no substantial increase in the severity of an environmental impact; 3) no other feasible project alternative or mitigation measure was identified that would clearly lessen the environmental impacts of the project and was considerably different from others previously analyzed, and 4) the Draft SEA did not deprive the public from meaningful review and comment. In addition, revisions to the proposed project and analysis in response to verbal or written comments during the rule development process would not create new, avoidable significant effects. As a result, these revisions do not require recirculation of the Draft SEA pursuant to CEQA Guidelines Sections 15073.5 and 15088.5. Therefore, the Draft SEA has been revised to include the aforementioned modifications such that it is now the Final SEA. The Final SEA will be presented to the Governing Board prior to its November 5, 2021 public hearing (see Attachment T of the Governing Board package).

When considering for approval a proposed project that has one or more significant adverse environmental effects, a public agency must make one or more written findings for each significant adverse effect, accompanied by a brief rationale for each finding [Public Resources Code Section 21081 and CEQA Guidelines Sections 15065 and 15091]. The analysis in the Final SEA concluded that the proposed project has the potential to generate, significant adverse environmental impacts which are more severe than what was previously analyzed in the December 2015 Final PEA for NOx RECLAIM for 1) air quality during construction and GHGs; 2) hazards and hazardous materials associated with ammonia; and 3) hydrology.

For a proposed project with significant adverse environmental impacts, CEQA requires the lead agency to balance the economic, legal, social, technological, or other benefits of a proposed project against its significant unavoidable environmental impacts when determining whether to approve the proposed project. Under CEQA Guidelines Section 15093(a), "If the specific economic, legal, social, technological, or other benefits of a project outweigh the unavoidable significant adverse environmental effects, the adverse environmental effects may be considered 'acceptable.'" Thus, after adopting findings, the lead agency must also adopt a "Statement of Overriding Considerations" to approve a proposed project with significant adverse environmental effects.

South Coast AQMD's certified regulatory program does not impose any greater requirements for making written findings for significant environmental effects than is required for an EIR under CEQA. When a lead agency adopts measures to mitigate or avoid significant adverse environmental effects, a mitigation, monitoring and reporting plan is required pursuant to CEQA Guidelines Section 15097 and Public Resources Code Section 21081.6. The Final SEA identified CEQA mitigation measures within the authority of South Coast AQMD to adopt or implement. Therefore, a Mitigation, Monitoring, and Reporting Plan is included in this document.

2.0 CEQA Provisions Regarding Findings

CEQA generally requires agencies to make certain written findings before approving a proposed project with significant environmental impacts. South Coast AQMD is exempt from some of CEQA's requirements pursuant to its Certified Regulatory Program, but complies with its provisions where required or otherwise appropriate.

Relative to making Findings, CEQA Guidelines Section 15091 provides:

(a) No public agency shall approve or carry out a project for which an EIR has been certified which identifies one or more significant environmental effects of the project unless the public agency makes one or more written findings for each of those significant effects, accompanied by a brief explanation of the rationale for each finding. The possible findings are:

1. Changes or alterations have been required in, or incorporated into, the project which avoid or substantially lessen the significant environmental effect as identified in the final EIR.
2. Such changes or alterations are within the responsibility and jurisdiction of another public agency and not the agency making the finding. Such changes have been adopted by such other agency or can and should be adopted by such other agency.
3. Specific economic, legal, social, technological, or other considerations, including provision of employment opportunities for highly trained workers, make infeasible the mitigation measures or project alternatives identified in the final EIR.

(b) The findings required by subsection (a) shall be supported by substantial evidence in the record.

(c) The finding in subdivision (a)(2) shall not be made if the agency making the finding has concurrent jurisdiction with another agency to deal with identified feasible mitigation measures or alternatives. The finding in subsection (a)(3) shall describe the specific reasons for rejecting identified mitigation measures and project alternatives.

(d) When making the findings required in subdivision (a)(1), the agency shall also adopt a program for reporting on or monitoring the changes which it has either required in the project or made a condition of approval to avoid or substantially lessen significant environmental effects. These measures must be fully enforceable through permit conditions, agreements, or other measures.

(e) The public agency shall specify the location and custodian of the documents or other material which constitute the record of the proceedings upon which its decision is based.

(f) A statement made pursuant to Section 15093 does not substitute for the findings required by this section.

The "changes or alterations" referred to in CEQA Guidelines Section 15091(a)(1) may include a wide variety of measures or actions as set forth in CEQA Guidelines Section 15370, including:

(a) Avoiding the impact altogether by not taking a certain action or parts of an action.

(b) Minimizing impacts by limiting the degree or magnitude of the action and its implementation.

(c) Rectifying the impact by repairing, rehabilitating, or restoring the impacted environment.

(d) Reducing or eliminating the impact over time by preservation and maintenance operations during the life of the action.

(e) Compensating for the impact by replacing or providing substitute resources or environments.

3.0 Summary of the Proposed Project

The proposed project is designed to transition affected sources (combustion equipment) specific to the petroleum refinery and related industries that emit NOx and that are operated at facilities subject to South Coast AQMD Regulation XX – RECLAIM to a command-and-control regulatory structure. The decision to transition from the NOx RECLAIM program to a source-specific command-and-control regulatory structure was approved by the South Coast AQMD Governing Board as Control Measure CMB-05 – Further NOx Reductions from RECLAIM Assessment of the 2016 AQMP. In accordance with Control Measure CMB-05, the transition of NOx RECLAIM facilities to a command-and-control regulatory structure is intended to ensure that the applicable equipment will meet BARCT level equivalency as soon as practicable. The potential environmental impacts associated with the 2016 AQMP, including Control Measure CMB-05, were analyzed in the March 2017 Final Program EIR for the 2016 AQMP.

The proposed project amends the previous BARCT assessments conducted for: 1) facilities in the refinery sector as previously analyzed in the December 2015 Final PEA for NOx RECLAIM; and 2) Control Measure CMB-05 and the entire RECLAIM Transition project in the 2016 Air Quality Management Plan (AQMP) as previously analyzed in the March 2017 Final Program EIR for the 2016 AQMP.

The amendments to the NOx RECLAIM program that were adopted on December 4, 2015 and which contained the previous BARCT assessment, were developed to reduce emissions from equipment and processes operated at NOx RECLAIM facilities located throughout the entire South Coast AQMD jurisdiction. The December 2015 Final PEA for NOx RECLAIM programmatically evaluated the environmental impacts of implementing that BARCT analysis, which was based on projected NOx emission reductions resulting from reducing NOx RECLAIM Trading Credit (RTC) allocations by up to 14 tons per day (tpd) from the refinery and non-refinery sectors. At the December 2015 public hearing, however, the South Coast AQMD Governing Board adopted a revised version of the NOx RECLAIM proposal with a reduced NOx RTC shave amount of 12 tpd, weighted for BARCT, and a delayed implementation schedule will full implementation by December 31, 2022.

PR 1109.1 was developed primarily to implement: 1) current BARCT which is statutorily required in California Health and Safety Code Section 40406 to consider "environmental, energy, and economic impacts;" and 2) AB 617 which contains an expedited schedule for implementing BARCT at cap-and-trade facilities since industrial source RECLAIM facilities are in the cap-and-trade program and are subject to the requirements of AB 617. Under AB 617, air districts are required to develop by January 1, 2019, an expedited schedule for the implementation of BARCT no later than December 31, 2023, with the highest priority given to older, higher-polluting units that will need retrofit controls installed.

PR 1109.1 proposes to establish BARCT requirements to reduce NOx emissions while not increasing carbon monoxide (CO) emissions from petroleum refineries and facilities with operations related to petroleum refineries which includes asphalt plants, biofuel plants, hydrogen production plants, facilities that operate petroleum coke calciners, sulfuric acid plants, and sulfur recovery plants. The following combustion equipment categories will be applicable to PR 1109.1: 1) boilers; 2) gas turbines; 3) ground level flares; 4) fluidized catalytic cracking units; 5) petroleum coke calciners; 6) process heaters; 7) sulfur recover units/tail gas treating units; 8) steam methane reformer (SMR) heaters; 9) SMR heaters with gas turbine; 10) sulfuric acid furnaces; and 11) vapor incinerators. To achieve the BARCT NOx concentration limits under PR 1109.1, installations or modifications of post-combustion NOx control equipment, including but not limited to selective catalytic reduction (SCR) and ultralow NOx burner (ULNB) technology, is expected to occur, which will reduce NOx emissions but may also increase emissions of particulate matter and sulfur oxide (SOx), which may trigger Best Available Control Technology (BACT).

PR 1109.1 will transition affected equipment operating at 16 facilities: nine petroleum refineries, three small refineries, and four facilities with related operations, that are subject to transition from the NOx RECLAIM program to a command-and-control regulatory structure. A portion of the equipment and facilities that are subject to PR 1109.1 were previously analyzed in the December 2015 Final PEA for NOx RECLAIM.

The BARCT NOx concentration limits in PR 1109.1 are expected to be achieved primarily by installing new or modifying existing post-combustion NOx control equipment such as selective catalytic reduction (SCR) technology or retrofitting existing combustion equipment with ultra-low NOx burners (ULNB). For FCCUs and petroleum coke calciners, wet gas scrubber (WGS) technology utilizing a Low Temperature Oxidation Application (LoTOx™ with WGS), or dry gas scrubber (DGS) technology utilizing an UltraCat™ Application (UltraCat™ with DGS) may be selected by facility operators in lieu of SCR technology to achieve the BARCT emission limits. Utilization of these various NOx emission control technologies is expected to create secondary adverse impacts which are analyzed in this CEQA document.

Although designed to reduce NOx emissions, installations of new or modifications of existing SCR technology to comply with the BARCT requirements in PR 1109.1 will cause concurrent increases in emissions of PM10 and SOx from the use of ammonia as a NOx reduction agent due to the presence of sulfur in the refinery fuel gas. In addition, these increases of co-pollutant emissions may, in turn, require facility operators to reduce the sulfur content in refinery fuel gas in order to comply with existing BACT requirements pursuant to New Source Review (NSR).

When comparing the types of activities and associated environmental impacts with implementing the BARCT standards for the equipment and facilities subject to the December 2015 NOx RECLAIM amendments as previously analyzed in the December 2015 Final PEA for NOx RECLAIM, to the additional equipment and sources that will need to comply with the BARCT requirements in PR 1109.1, the physical activities that facility operators may undertake to comply with the BARCT requirements in PR 1109.1 are expected to be the same and will cause the same type of secondary adverse environmental impacts affecting the same environmental topic areas that were identified and previously analyzed in the December 2015 Final PEA for NOx RECLAIM (e.g., air quality during construction and GHGs, hazards and hazardous materials due to ammonia, and hydrology (water demand) but to an extent that is more severe than the previous.

PR 429.1 proposes new requirements for startup, shutdown, and certain maintenance events, including an exemption from the NOx and CO emission limits in PR 1109.1 during these events. PR 429.1 also proposes notification and recordkeeping requirements for units that will be subject to PR 1109.1.

PAR 1304 and PAR 2005 propose to include a narrow BACT exemption to address these potential emission increases associated with installation of new or the modification of existing post-combustion air pollution control equipment or other equipment modifications to comply with the proposed NOx emission limits in PR 1109.1. Because the proposed adoption of PR 1109.1 will make Rule 1109 outdated and no longer necessary, Rule 1109 is proposed to be rescinded.

Implementation of the proposed project is estimated to reduce NOx emissions by approximately 7 to 8 tpd, while not increasing CO emissions. If the minimum 7 tpd of NOx emission reductions is achieved, a corresponding regionwide net decrease in annual PM2.5 concentration of 0.11 micrograms per cubic meter ($\mu g/m^3$) is also expected. While reducing emissions of NOx and other contaminants will create an environmental benefit, activities that facility operators may undertake to implement the proposed project may also create secondary potentially significant adverse environmental impacts to air quality during construction and GHGs; hazards and hazardous materials associated with ammonia; and hydrology.

4.0 Potential Significant Adverse Impacts That Cannot be Reduced Below a Significant Level

The Final SEA for the proposed project identified the topics of air quality during construction and GHGs, hazards and hazardous materials associated with ammonia, and hydrology as the areas in which the proposed project may make the significant adverse impacts previously analyzed in the December 2015 Final PEA for NOx RECLAIM more severe. The Final SEA for the proposed project did not identify any new significant impact areas. The analysis in the Final SEA for the proposed project, as with the previous analysis in the December 2015 Final PEA for NOx RECLAIM, is conservative as it makes the significance determinations assuming that almost all construction projects at all facilities will overlap, which is unlikely due to the potential for varying equipment turnaround schedules at the affected facilities. Thus, the analysis in the Final SEA likely overestimates the potentially significant adverse impacts that cannot be reduced below a significant level for the following environmental topic areas.

A. Air Quality Impacts During Construction

Relative to construction emissions, the "worst-case" scenario is when construction activities overlap due to concurrent construction activities occurring at a single facility and at multiple facilities. Specifically, the scenario analyzed in the Final SEA is the simultaneous activities of demolishing existing equipment, site preparation, and constructing new or modifying existing air pollution control equipment, which could occur at a single facility or at more than one facility. The analysis further assumes that the "worst-case" peak day is that in which each construction project is operating construction equipment that generates the greatest emissions.

The South Coast AQMD air quality significance thresholds for construction-related emissions are: 75 pounds per day of VOC; 100 pounds per day of NOx; 550 pounds per day of CO; 150 pounds per day of SOx; 150 pounds per day of PM10; and 55 pounds per day of PM2.5.

Based on the aforementioned assumptions for overlapping construction activities at 16 affected refinery facilities, the Final SEA for the proposed project estimated the "worst-case" peak daily mitigated emissions to be: 155 pounds of VOC; 1,062 pounds of NOx; 4,306 pounds of CO; 8 pounds of oxides of sulfur (SOx); 183 pounds of particulate matter with an aerodynamic diameter less than 10 microns (PM10); and 60 pounds of particulate matter with an aerodynamic diameter less than 2.5 microns (PM2.5).

For comparison, the December 2015 Final PEA for NOx RECLAIM estimated the "worst-case" peak daily mitigated construction emissions at nine affected refinery facilities to be: 389 pounds of VOC; 1,417 pounds of NOx; 2,396 pounds of CO; 3 pounds of SOx; 814 pounds of PM10; and, 405 pounds of PM2.5. For all pollutants, the incremental increase in mitigated construction emissions analyzed in the Final SEA for the proposed project, when added to the mitigated construction emissions presented in the December 2015 Final PEA for NOx RECLAIM, are more severe than the project analyzed in the December 2015 Final PEA for NOx RECLAIM, and except for SOx emissions, exceed the South Coast AQMD air quality significance thresholds for construction.

Thus, the proposed project evaluated in the Final SEA would result in more severe, significant adverse air quality impacts during construction than what were previously identified in the December 2015 Final PEA for NOx RECLAIM.

As such mitigation measures that focus on the VOC, NOx, CO, PM10, and PM2.5 emissions that may be generated during construction are required to minimize the significant air quality impacts associated with construction activities. Feasible construction-related mitigation measures were identified in the December 2015 Final PEA for NOx RECLAIM that may continue to be employed for the proposed project evaluated in the Final SEA to reduce emissions from heavy construction equipment and worker travel. See the Mitigation, Monitoring, and Reporting Plan section of this document for the air quality construction mitigation measures that have been applied to the proposed project.

While applying construction mitigation measures may reduce emissions associated with construction activities at the affected facilities to the maximum extent feasible, the proposed project will neither avoid the significant air quality impacts during construction nor reduce the construction emission impacts to less than significant levels.

While the air quality mitigation measures for construction that are identified in the Mitigation, Monitoring, and Reporting Plan section of this document may reduce construction emissions to the maximum extent feasible, none are mitigation measures that will avoid the significant impacts or reduce the construction air quality impacts to less than significant. Also, no other feasible mitigation measures have been identified to reduce construction air quality emissions to less than significant levels. Therefore, the proposed project is considered to have significant adverse unavoidable project-specific and cumulative air quality impacts during construction, after mitigation is applied.

B. GHG Impacts

With regard to GHG emissions, the proposed project involves mobile sources during construction and operation at 16 affected refinery facilities which generate combustion GHG emissions during construction and operation, as carbon dioxide (CO2), methane (CH4), and nitrous oxide (N2O). However, the proposed project does not affect equipment or operations that have the potential to emit non-combustion GHGs such as sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs) or perfluorocarbons (PFCs).

Installation of new or modification of existing air pollution control equipment to reduce NOx emissions as part of implementing the proposed project is expected to generate construction-related GHG emissions. In addition, based on the type and size of equipment affected by the proposed project, GHG emissions from the operation of the air pollution control equipment are likely to increase from current levels due to electricity and fuel use. The proposed project will also result in an increase of GHG operational emissions produced from additional truck hauling and deliveries necessary to accommodate the additional solid waste generation and increased use of supplies and chemicals such as catalyst.

For the purposes of addressing the GHG impacts of the proposed project, the overall impacts of CO2 equivalent (CO2e) emissions from the proposed project were estimated and evaluated from the earliest possible initial implementation of the proposed project with construction beginning in 2021. Once the proposed project is fully implemented, the potential NOx emission reductions would continue through the end of the useful life of the equipment. The analysis estimated CO2e emissions from all sources subject to the proposed project (construction and operation). Since installing new or modifying existing air control equipment requires advanced planning, engineering design, and permitting, the analysis of CO2e emissions spans from the beginning of the proposed project (e.g., no sooner than 2021) to the end of construction (2033-2034) at full implementation (e.g., construction of new or modified air pollution control equipment will be completed and operational) when the entire 7 to 8 tpd of the NOx emission reductions will be fully achieved.

Implementing the proposed project is expected to result in an incremental increase of GHG emissions relative to the amount previously analyzed in the December 2015 Final PEA for NOx RECLAIM from temporary construction activities, operational electricity use, and operational truck trips, which, in total, will contribute to an overall exceedance of the South Coast AQMD's air quality significance threshold for GHGs (e.g., 10,000 metric tons of CO2e emissions per year (MTCO2e/yr)). The Final SEA estimated the "worst-case" incremental GHG emissions increase from the proposed project to be 2,029 MTCO2e/yr which does not exceed the South Coast AQMD air quality significance threshold for GHGs. For the proposed project, none of the incremental increases in GHG emissions at each of the affected 16 refinery facilities were shown in the Final SEA to individually exceed the GHG industrial significance threshold of 10,000 MTCO2e/yr before or after mitigation.

For comparison, the December 2015 Final PEA for NOx RECLAIM estimated the "worst-case" GHG emissions for nine affected refinery facilities from temporary construction activities, operational electricity use, operational truck trips, and operational water conveyance to be 33,517 MTCO2e/yr which exceeded the South Coast AQMD air quality significance threshold for GHGs. After the certification of the December 2015 Final PEA for NOx RECLAIM, more precise CO2e intensity emission factors for the specific utilities which provide electricity to the affected facilities became available. As such, the Final SEA updated the initial GHG estimates for the project analyzed in the December 2015 Final PEA for NOx RECLAIM by applying the revised CO2e intensity emission factors accordingly. While the revised GHG emission estimates in the Final SEA reflecting the updated CO2e intensity emission factors for the project analyzed in December 2015 Final PEA for NOx RECLAIM resulted in fewer CO2e emissions overall, at 15,371 MTCO2e/yr, the updated GHG emission estimates continue to exceed the South Coast AQMD air quality significance threshold for GHGs. However, none of the projected increases in GHG emissions at each of the affected nine facilities as analyzed in the December 2015 Final PEA for NOx RECLAIM were shown to individually exceed the GHG industrial significance threshold of 10,000 MT CO2e/yr before or after mitigation.

When adding the incremental GHG emissions analyzed in the Final SEA for the proposed project to the adjusted GHG emissions estimates from the December 2015 Final PEA for NOx RECLAIM, fewer overall GHG emissions and less severe GHG impacts when compared to the original GHG estimates presented in the December 2015 Final PEA for NOx RECLAIM are expected, but at levels that will continue to exceed the South Coast AQMD air quality significance threshold of 10,000 MTCO2e/yr for GHGs. Thus, less severe but significant adverse GHG impacts than what were previously identified in the December 2015 Final PEA for NOx RECLAIM would remain if the proposed project is implemented. Therefore, the proposed project is considered to have significant and unavoidable adverse GHG impacts.

As such, mitigation measures that focus on GHG emissions that may be generated are required to minimize the significant adverse GHG impacts. Feasible GHG-specific mitigation measures were previously identified in the December 2015 Final PEA for NOx RECLAIM to reduce GHG emissions associated with conveyance of water needed to operate air pollution control equipment that utilize water. Recycled water projects and the utilization of recycled water are among the most direct ways to reduce GHG from combustion activities associated with conveying water to the affected facilities if water-intensive scrubbers are installed as a result of the proposed project.

However, the proposed project evaluated in the Final SEA did not identify any incremental increases in the use of air pollution control equipment (e.g., scrubbers) that utilize water, thus, no incremental increases in water use such that no corresponding incremental increases in GHG emissions specific to water conveyance were anticipated for the proposed project. Nonetheless, should any of the affected facilities elect to install the scrubbers previously analyzed in the December 2015 Final PEA for NOx RECLAIM, the previously identified GHG mitigation measures may continue to be employed for the proposed project evaluated in the Final SEA. See the Mitigation, Monitoring, and Reporting Plan section of this document for the GHG mitigation measures that have been applied to the proposed project.

While the GHG mitigation measures identified in the Mitigation, Monitoring, and Reporting Plan section of this document may reduce GHG emissions associated with water conveyance to the maximum extent feasible, none are mitigation measures that will avoid the significant impact or reduce the GHG impact to less than significant levels. Also, no other feasible mitigation measures have been identified that would either avoid or reduce the other categories of GHG emissions (e.g., from temporary construction activities, operational electricity use, operational truck trips) to less than significant levels. Therefore, the proposed project is considered to have significant adverse unavoidable cumulative GHG impacts, even after mitigation is applied.

C. Hazards and Hazardous Materials Impacts Associated With Ammonia

The Final SEA assumes that some facilities may opt to reduce NOx emissions by installing air pollution control equipment such as SCRs which require the use of ammonia, a chronic and acutely hazardous material. Further, an increase in the use of ammonia in response to the proposed project may increase the current existing risk setting associated with transportation/deliveries of ammonia (i.e., truck and road accidents), and the use and storage of ammonia (i.e. tank rupture). In particular, the analysis in the Final SEA assumes that as many as 25 additional new SCRs could be installed at seven facilities, while the analysis in the December 2015 Final PEA for NOx RECLAIM estimated that 83 new SCRs would be installed at nine facilities.

For the 25 new SCRs to be installed, an additional 5 tpd (equivalent to approximately 1,288 gallons per day) of aqueous ammonia (at 19 percent concentration) would be needed to operate the equipment. For comparison, the amount of ammonia projected to be needed in the December 2015 Final PEA for NOx RECLAIM analysis was approximately 39.5 tpd or 10,284 gallons per day to supply approximately 117 new SCRs (with 83 of the 117 new SCRs for the refinery facilities) (see December 2015 Final PEA for NOx RECLAIM, Subchapter 4.4 – Hazards and Hazardous Materials, pp. 4.4-10 through 4.4-11). As such, the incremental amount of ammonia that is expected to be needed to implement the proposed project is relatively small when compared to what was previously analyzed in the December 2015 Final PEA for NOx RECLAIM.

Consistent with the analysis of the project previously analyzed in the December 2015 Final PEA for NOx RECLAIM for the nine refinery facilities, it is also expected that the 16 affected facilities that are subject to the proposed project and analyzed in the Final SEA will receive ammonia from a local ammonia supplier located in the greater Los Angeles area. As with the previously analyzed project, deliveries of aqueous ammonia associated with the proposed project would also be made by tanker truck via public roads. For both the project previously analyzed in the December 2015 Final PEA for NOx RECLAIM and the proposed project analyzed in the Final SEA, the accidental release of ammonia from a delivery and use is a localized event (i.e., the release of ammonia would only affect the receptors that are within the zone of the toxic endpoint). Further, the accidental release from a delivery would also be temporally limited because deliveries are not likely to be made at the same time in the same area. Based on these limitations, the analysis in both the December 2015 Final PEA for NOx RECLAIM and the Final SEA assumed that an accidental release would be limited to a single delivery or single facility at a time. In the ammonia transportation release scenario for both of these CEQA documents, the distance to the toxic endpoint from a worst-case delivery truck release was estimated to be 0.4 mile. Since sensitive receptors are expected to be found within 0.4 mile from roadways, the hazards and hazardous materials impacts due to a delivery truck accident were concluded to be potentially significant. Therefore, as with the project previously analyzed in the December 2015 Final PEA for NOx RECLAIM, the proposed project was also concluded to have significant adverse hazards and hazardous materials impacts due to ammonia deliveries.

Facilities that choose to install air pollution control devices that use ammonia, such as SCR systems, would need ammonia tanks that range in size from 600 to 11,000 gallons in capacity, with daily usage varying by facility need. However, the ammonia tank rupture scenario as previously analyzed in the December 2015 Final PEA for NOx RECLAIM and in the analysis in the Final SEA both estimated a toxic endpoint distance of 0.1 mile from a ruptured tank spilling up to 12,100 gallons (110 percent of the maximum sized tank of 11,000 gallons) of aqueous ammonia at a 20% concentration. Facility 10, which was not previously analyzed in the December 2015 Final PEA for NOx RECLAIM, may install an SCR and new ammonia tank to comply with the NOx emission limits in PR 1109.1, but this facility has indicated that they intend to utilize an existing SCR equipped with an existing ammonia tank. Since it is speculative to predict or forecast where individual facilities will choose to site their new ammonia tanks, it is not possible to quantify the exact toxic endpoint that will result and therefore, it is not possible to conclusively determine that all sensitive receptors in proximity of an affected facility would not be located within the toxic endpoint distance. Therefore, the Final SEA conservatively considers the environmental consequences regarding hazards impacts from a catastrophic rupture of an ammonia tank as a potentially significant adverse hazards and hazardous materials impact.

For the project previously analyzed in the December 2015 Final PEA for NOx RECLAIM, the hazards and hazardous materials analysis concluded significant adverse hazards and hazardous materials impacts due to the routine transport, use and storage of ammonia. At the time the December 2015 Final PEA for NOx RECLAIM was certified, no feasible mitigation measures for avoiding or reducing hazards and hazardous materials impacts associated with the routine transport, use, and storage of ammonia were identified.

For the project evaluated in the December 2015 Final PEA for NOx RECLAIM as well as the proposed project evaluated in the Final SEA, no feasible mitigation measures were identified for the transportation of ammonia, over and above the extensive safety regulations that currently apply to delivery trucks that haul ammonia. However, feasible mitigation measures for the use and storage of ammonia were identified for the proposed project evaluated in the Final SEA that would reduce the risk of an offsite consequence due to the catastrophic rupture of an ammonia tank. See the Mitigation, Monitoring, and Reporting Plan section of this document for the ammonia mitigation measures that have been applied to the proposed project.

In general, while the ammonia mitigation measures that are identified in the Mitigation, Monitoring, and Reporting Plan section of this document may reduce the risk of an offsite consequence at each individual facility by preventing a catastrophic release of ammonia beyond a facility's property line and avoiding the exposure of ammonia to offsite sensitive receptors, the effectiveness of these mitigation measures is site-specific and depends on the proximity of the ammonia tank to property line and the capacity of each ammonia storage tank that is actually installed.

Due to the uncertainty of where each facility may site an ammonia tank and not knowing the size of each ammonia tank to be installed at the time of writing the Final SEA, the analysis of these feasible mitigation measures concluded that the potential risk of an offsite consequence due to the catastrophic rupture of an ammonia tank may remain significant after mitigation is applied. Thus, none of the ammonia mitigation measures will completely avoid the significant hazards and hazardous materials impacts associated with ammonia or reduce these impacts to less than significant levels. Therefore, the proposed project is considered to have significant adverse unavoidable project-specific and cumulative hazards and hazardous materials impacts for the routine transport, use, and storage of ammonia, after mitigation is applied.

D. Hydrology Impacts

<u>Water Demand During Hydrotesting</u>

As with the project previously analyzed in the December 2015 Final PEA for NOx RECLAIM, implementation of the proposed project analyzed in the Final SEA may cause potentially significant adverse hydrology (water demand) impacts associated with hydrotesting installed equipment after construction is completed, but prior to bringing the equipment online for operation. During hydrotesting, water is expected to be used to hydrostatically (pressure) test all storage tanks and pipelines to ensure each structure's integrity. Pressure testing or hydrotesting is typically a one-time event unless a leak is found.

The analysis in the Final SEA shows that the potential incremental increase in water use would be approximately 88,000 gallons for multiple facilities concurrently conducting hydrotesting activities and 286,000 gallons for the proposed project. For comparison, the hydrotesting analysis in the December 2015 Final PEA for NOx RECLAIM concluded that the potential incremental increase in water use would be approximately 319,000 gallons for multiple facilities concurrently conducting hydrotesting activities and 924,000 gallons for the NOx RECLAIM project. When combining the proposed project analyzed in the Final SEA with the NOx RECLAIM project analyzed in the December 2015 Final PEA for NOx RECLAIM, the potential water use from hydrotesting overall is 407,000 gallons needed for multiple facilities concurrently conducting hydrotesting, and 1,210,000 gallons for the combined projects, which is greater than the South Coast AQMD's significance threshold of 262,820 gallons per day of potable water. Thus, the amount of potable water that may be used on a daily basis for hydrotesting activities post-construction but prior to operation is potentially significant. Moreover, the proposed project evaluated in the Final SEA would result in more severe significant adverse water demand impacts associated with hydrotesting than what were previously identified in the December 2015 Final PEA for NOx RECLAIM.

Feasible mitigation measures specific to hydrotesting water demand were previously identified in the December 2015 Final PEA for NOx RECLAIM that may continue to be employed for the proposed project evaluated in the Final SEA to reduce or completely avoid the use of potable water for hydrotesting purposes by substituting the use of recycled water. See the Mitigation, Monitoring, and Reporting Plan section of this document for the hydrotesting mitigation measures that have been applied to the proposed project.

While applying the hydrotesting mitigation measures may reduce the use of potable water associated with hydrotesting the affected equipment to the maximum extent feasible, the proposed project will neither avoid the significant water demand impacts during hydrotesting nor reduce water demand impacts to less than significant levels since not all of the affected facilities may have access to recycled water or other sources of non-potable water such as treated process water (e.g., cooling tower blowdown water, etc.) that is temporarily re-routed or diverted from elsewhere within the facility.

Therefore, the proposed project is considered to have significant adverse unavoidable project-specific and cumulative water demand impacts during hydrotesting, after mitigation is applied.

Water Demand During Operation

The proposed project evaluated in the Final SEA did not identify any incremental increases in the use of air pollution control equipment (e.g., scrubbers) that utilize water. Further, the incremental changes evaluated in the Final SEA consist of installing additional new SCRs and associated ammonia storage tanks, modifying additional existing SCRs, replacing combustion equipment, and replacing burners with ULNBs, and none of these technologies utilize water for their operation. For this reason, no incremental increases in operational water demand were anticipated for the proposed project. However, significant adverse water demand impacts during operation were concluded for the previously proposed project analyzed the December 2015 Final PEA for NOx RECLAIM because scrubber technology was identified as requiring substantial amounts of water for its operation (e.g., 602,814 gallons of water per day). Thus, the analysis in the Final SEA also concluded significant adverse water demand impacts during operation.

Feasible mitigation measures specific to operational water demand were previously identified in the December 2015 Final PEA for NOx RECLAIM that may continue to be employed for the proposed project evaluated in the Final SEA, should any of the affected facilities elect to install the scrubbers previously analyzed in the December 2015 Final PEA for NOx RECLAIM. See the Mitigation, Monitoring, and Reporting Plan section of this document for the operational water demand mitigation measures that have been applied to the proposed project.

While the operational water demand mitigation measures identified in the Mitigation, Monitoring, and Reporting Plan section of this document may reduce potable water use associated with water conveyance to the maximum extent feasible, none are mitigation measures that will avoid the significant impact or reduce the operational water demand impact to less than significant levels. Therefore, the proposed project is considered to have significant adverse unavoidable project-specific and cumulative water demand impacts during operation, after mitigation is applied.

5.0 Findings Regarding Potentially Significant Environmental Impacts

The following potentially significant environmental impacts were analyzed in the Final SEA, and the effects of the proposed project were considered. Public Resources Code Section 21081(a) and CEQA Guidelines Section 15091(a) provide that a public agency shall not approve or carry out a project with significant environmental effects unless the public agency makes one or more written findings for each of those significant effects, accompanied by a brief explanation of the rationale for each finding. Additionally, the findings must be supported by substantial evidence in the record [CEQA Guidelines Section 15091(b)]. Three potential findings can be made for potentially significant impacts:

> **Finding 1:** Changes or alterations have been required in, or incorporated into, the project which avoid or substantially lessen the significant environmental effect as identified in the Final SEA [Public Resources Code Section 21081(a)(1) and CEQA Guidelines Section 15091(a)(1)].
>
> **Finding 2:** Such changes or alterations are within the responsibility and jurisdiction of another public agency and not the agency making the finding. Such changes have been adopted by such other agency or can and should be adopted by such other agency [Public Resources Code Section 21081(a)(2) and CEQA Guidelines Section 15091(a)(2)].
>
> **Finding 3:** Specific economic, legal, social, technological, or other considerations make infeasible the mitigation measures or project alternatives identified in the Final SEA [Public Resources Code Section 21081(a)(3) and CEQA Guidelines Section 15091(a)(3)].

As identified in the Final SEA and summarized in Section 2.0 of this Attachment, the proposed project's impacts, when added to the impacts analyzed in the December 2015 Final PEA for NOx RECLAIM, has the potential to make the previously significant and unavoidable adverse environmental impacts more severe than the NOx RECLAIM project evaluated in the December 2015 Final PEA for NOx RECLAIM for the environmental topics of: 1) air quality during construction; 2) hazards and hazardous materials due to ammonia; and 3) hydrology specific to water demand for conducting hydrotesting. Also, the proposed project's GHG impacts, when considered with the impacts analyzed in the December 2015 Final PEA for NOx RECLAIM has the potential to make the previously significant and unavoidable adverse environmental impacts less severe than the NOx RECLAIM project evaluated in the December 2015 Final PEA for NOx RECLAIM. Finally, the proposed project would not alter the previously significant and unavoidable adverse environmental impacts previously evaluated in the December 2015 Final PEA for NOx RECLAIM.

Further, based on the analysis in the Final SEA, essentially the same feasible mitigation measures that South Coast AQMD previously adopted for the project analyzed December 2015 Final PEA for NOx RECLAIM for the environmental topics of air quality during construction, GHGs, and hydrology (see Appendix A), also apply to the proposed project because they can reduce the proposed project's potentially significant environmental impacts. However, the wording of these previously adopted mitigation measures has been updated for clarity and consistency with mitigation measures from other, more recently adopted South Coast AQMD rule development projects with similar environmental impacts.

In addition, new mitigation measures are contained in the Final SEA relative to hazards and hazardous materials impacts due to the use and storage of ammonia. Moreover, none of the identified feasible mitigation measures are capable of avoiding or reducing the significant adverse impacts to less than significant levels. Thus, Finding 1 is not applicable to the proposed project.

Finally, all of the previously identified feasible CEQA mitigation measures for the environmental topics of air quality during construction, GHGs, and hydrology and the new CEQA mitigation measures for hazards and hazardous materials impacts due to the use and storage of ammonia, which are identified in the Final SEA are within the authority of South Coast AQMD to adopt or implement. Thus, Finding 2 is not applicable to the proposed project.

The Final SEA concluded that the overall project (impacts from the proposed project added to the impacts from the NOx RECLAIM project) will have the potential to generate significant and unavoidable adverse environmental impacts that are more severe than the project previously analyzed in the December 2015 Final PEA for NOx RECLAIM for the same environmental topics of: 1) air quality during construction; 2) hazards and hazardous materials due to ammonia; and 3) hydrology specific to water demand for conducting hydrotesting. Also, the proposed project's GHG impacts, when considered with the impacts analyzed in the December 2015 Final PEA for NOx RECLAIM has the potential to make the previously significant and unavoidable adverse environmental impacts less severe than the NOx RECLAIM project evaluated in the December 2015 Final PEA for NOx RECLAIM. Finally, the proposed project would not alter the previously significant and unavoidable adverse environmental impacts previously evaluated in the December 2015 Final PEA for NOx RECLAIM.

The South Coast AQMD Governing Board, therefore, makes the following findings regarding the proposed project. The findings are supported by substantial evidence in the record as explained in each finding. The findings will be included in the record of project approval and will also be noted in the Notice of Decision. The findings made by the South Coast AQMD Governing Board are based on the following significant adverse impacts identified in the Final SEA for the proposed project and the previous findings made by the South Coast AQMD Governing Board for the project analyzed in the December 2015 Final PEA for NOx RECLAIM, which are incorporated by reference and are included as Appendix A to this document.

A. Potential project-specific and cumulative VOC, CO, NOx, PM10, and PM2.5 emissions during construction exceed the South Coast AQMD's applicable significance air quality thresholds and cannot be mitigated to less than significant levels.

Finding and Explanation:
When compared to the project previously analyzed in the December 2015 Final PEA for NOx RECLAIM, the implementation of the proposed project is anticipated to trigger additional construction activities associated with the installation of new or the modification of existing air pollution control equipment, the retrofit of existing combustion equipment and the replacement of combustion equipment. Construction activities associated with the proposed project would result in incremental increases of VOC, CO NOx, SOx, PM10, and PM2.5 emissions. For all pollutants, the mitigated construction emissions analyzed in the

Final SEA for the proposed project are more severe than the project analyzed in the December 2015 Final PEA for NOx RECLAIM, and except for SOx emissions, exceed the South Coast AQMD air quality significance thresholds for construction.

As a result, the proposed project is expected to have significant adverse construction air quality impacts. However, the temporary construction emissions would cease upon completion of the installation of new or the modification of existing air pollution control equipment, the retrofit of existing combustion equipment and the replacement of combustion equipment, as applicable. Once all the modified or new equipment are in place, the proposed project is expected to result in an incremental reduction of NOx emissions of 7 to 8 tpd per day by 2033-2034, with some of these reductions achieved above and beyond the actual reductions expected from the refinery sector in the December 2015 NOx RTC shave.

Because there are more severe, significant adverse air quality impacts during construction, the Final SEA describes feasible mitigation measures which are essentially the same mitigation measures identified in the December 2015 Final PEA for NOx RECLAIM that could minimize these significant adverse impacts. However, the wording of these previously adopted mitigation measures has been updated for clarity and consistency with mitigation measures from other, more recently adopted South Coast AQMD rule development projects with similar environmental impacts.

The Governing Board finds that the updated versions of the construction air quality mitigation measures that have been previously identified and adopted for the December 2015 Final PEA for NOx RECLAIM apply to the proposed project but they would not reduce the significant adverse project-specific or cumulative impacts to air quality associated with construction to less than significant levels. No other feasible mitigation measures have been identified.

B. Potential GHG emissions exceed the South Coast AQMD's applicable significance GHG threshold and cannot be mitigated to less than significant levels.

Finding and Explanation:
When compared to the project previously analyzed in the December 2015 Final PEA for NOx RECLAIM, the implementation of the proposed project is anticipated to have incremental increases in GHG emissions associated with additional construction activities pertaining to the installation of new or the modification of existing air pollution control equipment, the retrofit of existing combustion equipment and the replacement of combustion equipment and the operation of this new and/or modified equipment.

For both the project previously analyzed in the December 2015 Final PEA and the proposed project analyzed in the Final SEA, none of the affected facilities individually exceed the South Coast AQMD's industrial GHG significance threshold of 10,000 MT CO2e/yr, if the proposed project is implemented. However, when all of the GHG emissions for the facilities were considered for the entire project analyzed in the December 2015 Final PEA for NOx RECLAIM, the analysis indicated that there would be a significant increase in

GHG emissions. Adding the incremental increases of GHG emissions from the proposed project to the previous GHG emission estimates from the December 2015 Final PEA for NOx RECLAIM results in more severe GHG emission impacts overall, and when considered together, will continue to exceed the South Coast AQMD air quality significance thresholds for GHGs. However, due to the adjustments in the electricity utility emission factors, the total amount of GHGs from the proposed project and the NOx RECLAIM project combined are less than what was originally estimated for only the NOx RECLAIM project in the December 2015 Final PEA for NOx RECLAIM. Thus, the proposed project evaluated in the Final SEA would result in less severe but significant adverse GHG impacts than what were previously identified in the December 2015 Final PEA for NOx RECLAIM. Because there are significant adverse GHG impacts from the proposed project, the SEA must describe feasible measures that could minimize significant adverse impacts.

Because there are more severe, significant adverse GHG impacts, the Final SEA describes feasible mitigation measures which are essentially the same mitigation measures identified in the December 2015 Final PEA for NOx RECLAIM that could minimize these significant adverse impacts. However, the wording of these previously adopted mitigation measures has been updated for clarity and consistency with mitigation measures from other, more recently adopted South Coast AQMD rule development projects with similar environmental impacts.

The Governing Board finds that the updated versions of the GHG mitigation measures that have been previously identified and adopted for the December 2015 Final PEA for NOx RECLAIM apply to the proposed project, but they would not reduce the significant adverse GHG emission impacts to less than significant levels. No other feasible GHG mitigation measures have been identified.

C. Potential hazards and hazardous materials impacts due to the transportation, use, and storage of ammonia may significantly increase the risk of an offsite consequence due to a release of ammonia and cannot be mitigated to less than significant levels.

<u>I. Finding and Explanation Regarding Transportation of Ammonia:</u>
For both the project previously analyzed in the December 2015 Final PEA for NOx RECLAIM and the proposed project analyzed in the Final SEA, the hazards and hazardous materials analysis concluded significant adverse hazards and hazardous materials impacts due to the routine transport of ammonia to facilities that may install air pollution control equipment that require the use of ammonia. However, the proposed project evaluated in the Final SEA would result in more severe hazards and hazardous materials impacts due to the routine transport of ammonia to facilities than what were previously identified in the December 2015 Final PEA for NOx RECLAIM primarily due to more facilities receiving ammonia and more ammonia being transported overall.

For the project evaluated in the December 2015 Final PEA for NOx RECLAIM as well as the proposed project evaluated in the Final SEA, no feasible mitigation measures were identified for the transportation of ammonia, over and above the extensive safety regulations that currently apply to delivery trucks that haul ammonia.

Therefore, the Governing Board finds that no feasible mitigation measures have been identified that would reduce the significant adverse hazards and hazardous materials impacts due to the transportation of ammonia.

II. Finding and Explanation Regarding Use and Storage of Ammonia:
For both the project previously analyzed in the December 2015 Final PEA for NOx RECLAIM and the proposed project analyzed in the Final SEA, the hazards and hazardous materials analysis concluded significant adverse hazards and hazardous materials impacts due to the use and storage of ammonia at facilities that may install that may install air pollution control equipment that require the use of ammonia.. At the time the December 2015 Final PEA for NOx RECLAIM was certified, no feasible mitigation measures for avoiding or reducing hazards and hazardous materials impacts associated with the use and storage of ammonia were identified.

However, for the proposed project evaluated in the Final SEA, new feasible mitigation measures for the use and storage of ammonia were identified that would reduce the risk of an offsite consequence at each individual facility by preventing a catastrophic release of ammonia beyond a facility's property line and avoiding the exposure of ammonia to offsite sensitive receptors. The effectiveness of these mitigation measures is site-specific and depends on the proximity of the ammonia tank to property line and the capacity of each ammonia storage tank that is actually installed.

Due to the uncertainty of where each facility may site an ammonia tank and not knowing the size of each ammonia tank to be installed at the time of writing the Final SEA, the analysis of these feasible mitigation measures concluded that the potential risk of an offsite consequence due to the catastrophic rupture of an ammonia tank may remain significant after mitigation is applied. Thus, none of the ammonia mitigation measures will completely avoid the significant hazards and hazardous materials impacts associated with ammonia or reduce these impacts to less than significant levels. Therefore, the proposed project is considered to have significant adverse unavoidable project-specific and cumulative hazards and hazardous materials impacts for the use and storage of ammonia, after mitigation is applied.

Therefore, the Governing Board finds that feasible mitigation measures have been identified for significant adverse hazards and hazardous materials impacts due to the use and storage of ammonia, but these mitigation measure would not be able to reduce the potential impacts to less than significant levels.

D. Potential potable water demand would use a substantial amount of potable water during hydrotesting and operation which cannot be mitigated to less than significant levels.

I. Finding and Explanation Regarding Water Needed for Hydrotesting:
As with the project previously analyzed in the December 2015 Final PEA for NOx RECLAIM, implementation of the proposed project analyzed in the Final SEA may cause potentially significant adverse hydrology (water demand) impacts associated with hydrotesting installed equipment after construction is completed, but prior to bringing the equipment online for operation. Moreover, the proposed project evaluated in the Final SEA would result in more severe significant adverse water demand impacts associated with hydrotesting than what were previously identified in the December 2015 Final PEA for NOx RECLAIM.

Feasible mitigation measures specific to hydrotesting water demand were previously identified in the December 2015 Final PEA for NOx RECLAIM that may continue to be employed for the proposed project evaluated in the Final SEA to reduce or completely avoid the use of potable water for hydrotesting purposes by substituting the use of recycled water.

While applying the hydrotesting mitigation measures may reduce the use of potable water associated with hydrotesting the affected equipment to the maximum extent feasible, the proposed project will neither avoid the significant water demand impacts during hydrotesting nor reduce water demand impacts to less than significant levels since not all of the affected facilities may have access to recycled water or other sources of non-potable water such as treated process water (e.g., cooling tower blowdown water, etc.) that is temporarily re-routed or diverted from elsewhere within the facility. Therefore, the proposed project is considered to have significant adverse unavoidable project-specific and cumulative water demand impacts during hydrotesting, after mitigation is applied.

Because there are more severe significant adverse hydrology impacts associated with conducting hydrotesting, the Final SEA describes feasible measures which are essentially the same mitigation measures identified in the December 2015 Final PEA for NOx RECLAIM that could minimize these significant adverse impacts. However, the wording of these previously adopted mitigation measures has been updated for clarity and consistency with mitigation measures from other, more recently adopted South Coast AQMD rule development projects with similar environmental impacts.

The Governing Board finds that the updated versions of the hydrotesting mitigation measures that have been previously identified and adopted for the December 2015 Final PEA for NOx RECLAIM apply to the proposed project, but they would not reduce the significant adverse water demand impacts associated with hydrotesting to less than significant levels. No other feasible hydrotesting mitigation measures have been identified.

II. Finding and Explanation Regarding Water Needed During Operation:
The proposed project evaluated in the Final SEA did not identify any incremental increases in the use of air pollution control equipment (e.g., scrubbers) that utilize water. Further, the incremental changes evaluated in the Final SEA consist of installing additional new SCRs and associated ammonia storage tanks, modifying additional existing SCRs, replacing combustion equipment, and replacing burners with ULNBs, and none of these technologies utilize water for their operation. For this reason, no incremental increases in operational water demand were anticipated for the proposed project. However, significant adverse water demand impacts during operation were concluded for the previously proposed project analyzed the December 2015 Final PEA for NOx RECLAIM because scrubber technology was identified as requiring substantial amounts of water for its operation. Thus, the analysis in the Final SEA also concluded significant adverse water demand impacts during operation.

While the proposed project does not increase the severity of the significant operational hydrology (water demand) impacts analyzed in the December 2015 Final PEA for NOx RECLAIM, should any of the affected facilities elect to install the previously analyzed scrubbers, the previous feasible mitigation measures specific to operational water demand may continue to be employed for the proposed project. Thus, the Final SEA describes feasible measures which are essentially the same mitigation measures identified in the December 2015 Final PEA for NOx RECLAIM that could minimize these significant adverse impacts. However, the wording of these previously adopted mitigation measures has been updated for clarity and consistency with mitigation measures from other, more recently adopted South Coast AQMD rule development projects with similar environmental impacts.

While the operational water demand mitigation measures may reduce potable water use associated with water conveyance to the maximum extent feasible, none are mitigation measures that will avoid the significant impact or reduce the operational water demand impact to less than significant levels. Therefore, the proposed project is considered to have significant adverse unavoidable project-specific and cumulative potable water demand impacts during operation, after mitigation is applied.

The Governing Board finds that the updated versions of the hydrology mitigation measures for operational demand of potable water that have been previously identified and adopted for the December 2015 Final PEA for NOx RECLAIM apply to the proposed project, but they would not reduce or avoid the significant adverse operational water demand impacts to less than significant levels for potable water. No other feasible mitigation measures for operational potable water demand have been identified.

5.1 Findings For Alternatives to the Proposed Project

A. Alternative A: No Project

Finding and Explanation:
The Final SEA analyzes a No Project Alternative, referred to as Alternative A, which consists of what would occur if the proposed project is not approved or adopted. Under Alternative A, petroleum refineries and facilities related to petroleum refineries would remain subject to the NOx RECLAIM program (e.g., South Coast AQMD Regulation XX) would not become subject to a command-and-control rule. The NOx RECLAIM program is based on a comprehensive set of rules, requirements, and procedures ensuring affected facilities operate under a mass emission cap for NOx (referred to as annual allocations) subject to periodic reductions or "shave," to demonstrate equipment operations are equivalent with BARCT. Meeting this shave can be done through the installation and operation of NOx control equipment to reduce NOx emissions or by providing NOx RTCs. The proposed project is seeking to transition these facilities from the mass emission cap and NOx RTC approach allowed by RECLAIM to a command-and-control regulatory structure whereby a NOx concentration limit is applied to each piece of combustion equipment to comply with BARCT requirements.

Under Alternative A, facilities remaining subject to the NOx RECLAIM program ould still be subject to the 12 tpd NOx RTC shave by the end of 2022. It is also important to note that Alternative A, by design, would violate the state law adopted pursuant to AB 617 which requires air districts "in nonattainment for one or more air pollutants to adopt an expedited schedule for the implementation of best available retrofit control technology, as specified." AB 617 applies to each industrial source that, as of January 1, 2017, was subject to a specified market-based compliance mechanism (e.g., CARB's AB 32 Cap-and-Trade program for GHGs) and gives highest priority to those permitted units that have not modified emissions-related permit conditions for the greatest period of time. Thus, facilities would still need to be evaluated under a BARCT analysis and, depending on the outcome of that analysis, would need to take action to comply. However, the BARCT analysis under Alternative A and the proposed project is expected to be the same with the same determinations and NOx emission limits. The major difference is that under the NOx RECLAIM program, facilities could opt to use NOx RTCs to meet allocation goals without having to make physical modifications such as installing air pollution control technology. Other elements in PR 1109.1 such as averaging times, exemptions, recordkeeping, reporting, and monitoring would also be different under the RECLAIM program. In addition, Action 5 of the Refinery priorities in the AB 617 Community Emissions Reduction Plan (CERP) for the Wilmington, Carson, West Long Beach community specifically contains a directive for South Coast AQMD to adopt PR 1109.1; thus, the No Project alternative would hinder the full implementation of the AB 617 CERP for the Wilmington, Carson, West Long Beach community, as well as implementation of control measure CMB-05 in the 2016 AQMP.

Alternative A is less environmentally beneficial than the proposed project because it would forego: 1) the 7 to 8 tpd of NOx emission reductions by 2033-2034 (while not increasing

CO emissions) with some of these reductions achieved above and beyond the actual reductions expected from the refinery sector in the December 2015 NOx RTC shave; and 2) a corresponding regionwide net decrease in annual PM2.5 concentration of 0.11 $\mu g/m^3$. The No Project alternative is also not capable of meeting the proposed project's basic objective to transition equipment that is currently permitted under the NOx RECLAIM program to a command-and-control regulatory structure. Because Alternative A is not environmentally superior to the proposed project and does not achieve the basic project objective, the No Project Alternative is infeasible [Public Resources Code 21081(a)(3); *California Native Plant Society v. City of Santa Cruz* (2009) 177 Cal.App.4th 957, 1000-1001 (upholding finding of infeasibility where agency determined alternative failed to achieve project objective)].

B. Alternative B: More Stringent Proposed Project

Finding and Explanation:
The Final SEA analyzes Alternative B, which is more stringent than the proposed project. Alternative B proposes to apply earlier deadlines than what would otherwise be required in PR 1109.1 for small heaters to achieve a NOx concentration of nine ppm within five years as opposed to 10 years, and small boilers to achieve a NOx concentration of five ppm within six months replacing 25% or more burners as opposed to 50%. All other elements, limits, and deadlines would be the same under Alternative B as for the proposed project.

Alternative B would achieve equivalent long-term NOx emission reductions as the proposed project, as follows: 1) 7 to 8 tpd of NOx emission reductions by 2033-2034 (while not increasing CO emissions) with some of these reductions achieved above and beyond the actual reductions expected from the refinery sector in the December 2015 NOx RTC shave; and 2) a corresponding regionwide net decrease in annual PM2.5 concentration of 0.11 $\mu g/m^3$. However, by shortening the compliance timeline, incremental NOx emission reductions 0.37 ton per day from heaters and boilers rated less than 40 MMBTU/hr would be achieved earlier than the proposed project. Of the alternatives analyzed, Alternative B was identified in the Final SEA as the environmentally superior alternative. However, since installing new or modifying existing air control equipment requires advanced planning, engineering design, and permitting, under Alternative B's more compressed implementation timelines, there may be limited resources available since facilities will be competing for the same skilled labor pool, equipment from the same manufacturers, source test companies, etc. In addition, the compressed compliance implementation timelines outlined in Alternative B will lead to more construction activities and greater construction emissions occurring on peak day which will exceed the South Coast AQMD air quality significance thresholds to a larger extent than the proposed project. As such, Alternative B will not avoid or substantially lessen the significant environmental effect as identified in the Final SEA [Public Resources Code Section 21081(a)(1) and CEQA Guidelines Section 15091(a)(1)].

C. Alternative C: Less Stringent Proposed Project

I. Finding and Explanation:

The Final SEA analyzes Alternative C, which is less stringent that the proposed project. Alternative C proposes to extend the I-Plan option time frames and lower percentage reduction targets in Phases I by half and in Phase II by a lesser amount with 100% reduction target being achieved by the end of Phase III. All other elements, limits, and deadlines would be the same under Alternative C as for the proposed project.

Alternative C would achieve equivalent long-term NOx emission reductions as the proposed project, as follows: 1) 7 to 8 tpd of NOx emission reductions by 2033-2034 (while not increasing CO emissions) with some of these reductions achieved above and beyond the actual reductions expected from the refinery sector in the December 2015 NOx RTC shave; and 2) a corresponding regionwide net decrease in annual PM2.5 concentration of 0.11 µg/m^3. However, by lengthening the compliance timeline, facilities would presumably delay construction projects and incremental emission reductions would be achieved later. Air quality impacts due to construction on a peak day could decrease, but it would be speculative to estimate how much. As such, the South Coast AQMD Governing Board finds that Alternative C will not avoid or substantially lessen the significant environmental effect as identified in the Final SEA [Public Resources Code Section 21081(a)(1) and CEQA Guidelines Section 15091(a)(1)].

D. Alternative D: Limited Start-up, Shutdown, and Malfunction

I. Finding and Explanation:

The Final SEA analyzes Alternative D, which would halve allowance time periods for boilers and process heaters with NOx post-combustion control equipment, SMR heaters, sulfuric acid furnaces, SMR heaters with gas turbines, FCCUs, petroleum coke calciners, and SRU/TG incinerators during start-ups, shutdowns, and malfunctions (SSM), pursuant to the definitions in the PR 429.1, to not be considered when determining compliance with the NOx emission limits in PR 1109.1.

Alternative D would achieve equivalent long-term NOx emission reductions as the proposed project, as follows: 1) 7 to 8 tpd of NOx emission reductions by 2033-2034 (while not increasing CO emissions) with some of these reductions achieved above and beyond the actual reductions expected from the refinery sector in the December 2015 NOx RTC shave; and 2) a corresponding regionwide net decrease in annual PM2.5 concentration of 0.11 µg/m^3. While shortening the SSM allowance period reduces unaccounted-for short-term emissions and total emissions could be expected to decrease with the increasing of total compliance time, it would be speculative to quantify the emission benefit. As such, the South Coast AQMD Governing Board finds that Alternative D will not avoid or substantially lessen the significant environmental effect as identified in the Final SEA [Public Resources Code Section 21081(a)(1) and CEQA Guidelines Section 15091(a)(1)].

5.2 Conclusion of Findings

The Governing Board makes the following findings:

1) Essentially the same feasible mitigation measures that were identified to help minimize the potentially significant adverse impacts to the topics of air quality during construction, GHG emissions, and hydrology and that were adopted by the South Coast AQMD Governing Board at its December 4, 2015 public hearing for the project analyzed in the December 2015 Final PEA for NOx RECLAIM apply to the proposed project analyzed in the Final SEA such that a Mitigation, Monitoring, and Reporting Plan (pursuant to Public Resources Code Section 21081.6) needs to be prepared. However, the wording of these previously adopted mitigation measures has been updated for clarity and consistency with mitigation measures from other, more recently adopted South Coast AQMD rule development projects with similar environmental impacts.
2) New feasible mitigation measures were identified in the Final SEA that will help minimize the potentially significant adverse impacts to the topics of hazards and hazardous materials due to the use and storage of ammonia and these new mitigation measures are included in the Mitigation, Monitoring, and Reporting Plan.
3) No feasible mitigation measures have been identified in the Final SEA that would help minimize the potentially significant adverse impacts to hazards and hazardous materials due to transportation of ammonia.
4) Alternative A, the No Project alternative, is infeasible because it is not environmentally superior to the proposed project, does not achieve all of the project objectives, and it violates AB 617, which is state law [Public Resources Code Section 21081(a)(3) and CEQA Guidelines Section 15091(a)(3)].
5) Alternative B, which was identified in the Final SEA as the environmentally superior alternative, and Alternatives C and D will not avoid or substantially lessen the significant environmental effects identified in the Final SEA [Public Resources Code Section 21081(a)(1) and CEQA Guidelines Section 15091(a)(1)].

CEQA defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors." [Public Resources Code Section 21061.1].

The Governing Board further finds that the Final SEA considered alternatives pursuant to CEQA Guidelines Section 15126.6, but there is no alternative to the project that would reduce to insignificant levels the significant impacts to the topics of air quality during construction, GHG emissions, hazards and hazardous materials due to deliveries of ammonia, and hydrology that were identified for the proposed project.

The Governing Board further finds that the findings required by CEQA Guidelines Section 15091(a) are supported by substantial evidence in the record.

6.0 Statement of Overriding Considerations

If significant adverse impacts of a proposed project remain after incorporating mitigation measures, or no measures or alternatives to mitigate the adverse impacts are identified, the lead agency must make a determination that the benefits of the project outweigh the unavoidable adverse environmental effects if it is to approve the project. CEQA requires the decision-making agency to balance, as applicable, the economic, legal, social, technological, or other benefits of a proposed project against its unavoidable environmental risks when determining whether to approve the project [CEQA Guidelines Section 15093(a)]. If the specific economic, legal, social, technological, or other benefits of a proposed project outweigh the unavoidable adverse environmental effects, the adverse environmental effects may be considered "acceptable" [CEQA Guidelines Section 15093(a)]. Accordingly, a Statement of Overriding Considerations regarding potentially significant adverse impacts to air quality during construction and GHGs, hazards and hazardous materials associated with ammonia, and hydrology that may result from the proposed project has been prepared. This Statement of Overriding Considerations is included as part of the record of the project approval for the proposed project. Pursuant to CEQA Guidelines Section 15093(c), the Statement of Overriding Considerations will also be noted in the Notice of Decision for the proposed project.

Despite the inability to incorporate changes into the proposed project that will mitigate potentially significant adverse impacts to less than significant levels for the topics of air quality during construction and GHGs, hazards and hazardous materials associated with ammonia, and hydrology, the South Coast AQMD Governing Board finds that each and every one of the following benefits and considerations individually outweigh each and every one of the significant unavoidable adverse environmental impacts:

1. The analysis of potential adverse environmental impacts incorporates a "worst-case" approach. This entails the premise that whenever the analysis requires that assumptions be made, those assumptions that result in the greatest adverse impacts are typically chosen. This method likely overestimates the actual environmental impacts from the proposed project.

2. The 2016 AQMP identifies ambient air pollutant levels relative to federal and state ambient air quality standards (AAQS), establishes baseline and future emissions, and develops control measures to ensure attainment of the AAQS. Construction is a continuous activity within South Coast AQMD's jurisdiction which has been previously addressed in the 2016 AQMP. Thus, any changes in air quality as a result of construction emissions from the proposed project are accounted for in the 2016 AQMP and would not be expected to interfere with the attainment demonstrations.

3. The proposed project supports the implementation of 2016 AQMP Control Measure CMB-05 – Further NOx Reductions from RECLAIM Assessment which is designed to transition NOx RECLAIM facilities to a command-and-control regulatory structure and to ensure that the applicable equipment will meet BARCT level equivalency as soon as practicable.

4. The proposed project also supports the previous amendments to the NOx RECLAIM program as adopted on December 4, 2015 which contain the previous BARCT assessment

and which were developed to reduce emissions from equipment and processes operated at NOx RECLAIM facilities located throughout the entire South Coast AQMD jurisdiction. The previously adopted amendments to the NOx RECLAIM program will remove 12 tpd of NOx RTCs by December 31, 2022.

5. The proposed project conforms with AB 617, which is a state law requiring implementation of BARCT no later than December 31, 2023, with the highest priority given to older, higher-polluting units that will need retrofit controls installed and Action 5 of the Refinery priorities in the AB 617 CERP for the Wilmington, Carson, West Long Beach community which specifically contains a directive for South Coast AQMD to adopt a rule requiring BARCT for refineries, as reflected PR 1109.1.

6. Each of the alternatives was crafted to vary compliance times: whether implementation dates for source-specific NOx emission limits or facility percentage reduction targets, or start-up, shutdown, and malfunction allowances; all alternatives would achieve equivalent long-term NOx emission reductions as the proposed project. Shortening of compliance times could result in incremental emission reductions being achieved sooner, but would set unrealistic requirements for affected facilities. Lengthening of compliance times could be expected to reduce short-term air quality construction impacts, but because there are various possibilities or permutations of how operators would install equipment to achieve actual NOx reductions, ultimately, there is no way quantify this reduction and conclude impacts to be less than significant.

7. Although the proposed project will not incrementally achieve emission reductions the quickest as compared to more stringent alternatives, it is considered to provide the best balance between emission reductions, feasibility, and the adverse environmental impacts due to construction and operation activities while meeting the overall objectives.

8. Implementing the proposed project will result in an overall net reduction of NOx emissions by approximately 7 to 8 tpd, while not increasing CO emissions. If the minimum 7 tpd of NOx emission reductions is achieved for the proposed project overall, a corresponding regionwide net decrease in annual PM2.5 concentration of 0.11 $\mu g/m^3$ is also expected. Therefore, cumulative air quality impacts from the proposed project and all other AQMP control measures when considered together, are not expected to be significant because implementation of all AQMP control measures, and in particular, this project, is expected to result in net emission reductions and overall air quality improvement.

The South Coast AQMD Governing Board finds that the above-described considerations outweigh the unavoidable significant effects to the environment as a result of the proposed project.

7.0 Mitigation, Monitoring, and Reporting Plan

When making findings as required by Public Resources Code Section 21081 and CEQA Guidelines Section 15091, the lead agency must adopt a reporting or monitoring program for the changes to the project which it has adopted or made a condition of project approval in order to mitigate or avoid significant effects on the environment [Public Resources Code Section 21081.6 and CEQA Guidelines Section 15097(a)]. To fulfill the requirements of Public Resources Code

Section 21081.6 and CEQA Guidelines Section 15097, the South Coast AQMD has developed the following Mitigation, Monitoring, and Reporting Plan for anticipated impacts resulting from implementing the proposed project. Each operator of any facility required to comply with the Mitigation Monitoring, and Reporting Plan shall keep records onsite of applicable compliance activities to demonstrate the steps taken to assure compliance with all of the mitigation measures, as applicable.

The following construction mitigation measures are required for each of the affected facilities whose operators choose to install air pollution control equipment in response to the proposed project. If, at the time when each facility-specific project is proposed, South Coast AQMD staff will conduct a CEQA evaluation of the facility-specific project and determine if the project is covered by the analysis in the Final SEA. If, at the time when each facility-specific project is proposed, that improved emission reduction technologies become available for on- and off-road construction equipment, the construction mitigation measures will be updated accordingly as part of the CEQA evaluation for the facility-specific project. In addition, these mitigation measures will be included in a Mitigation, Monitoring, and Reporting Plan as part of issuing South Coast AQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by South Coast AQMD personnel.

A. Air Quality Impacts During Construction

Impacts Summary: The proposed project makes more severe, the construction air quality impacts previously analyzed under the December 2015 Final PEA for NOx RECLAIM. Project-specific and cumulative construction-related emissions of VOC, NOx, CO, PM10, and PM2.5 emissions, based on a “worst-case” analysis, would exceed the South Coast AQMD’s regional mass daily significance thresholds for these pollutants. Emission sources include worker vehicles and heavy construction equipment. The following mitigation measures are intended to minimize the emissions associated with these sources during construction activities. No feasible mitigation measures have been identified to reduce emissions to less than significant levels.

Mitigation Measures: The following construction mitigation measures are required for each of the affected facilities whose operators choose to install NOx control equipment. South Coast AQMD staff will conduct a CEQA evaluation of each facility-specific project proposed in response to the proposed project and determine if the project is covered by the analysis in the Final SEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing South Coast AQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by South Coast AQMD personnel.

AQ-1 Develop a Construction Emission Management Plan for each affected facility to minimize emissions from vehicles including, but not limited to: consolidating truck deliveries; scheduling deliveries to avoid peak hour traffic conditions; describing truck routing; describing deliveries including logging delivery times; describing entry/exit points; identifying locations of parking; identifying construction schedule; and prohibiting truck idling in excess of five consecutive minutes or another time-frame as allowed by the California Code of Regulations, Title 13 Section 2485 - CARB's Airborne Toxic Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling. The Construction Emission Management Plan shall be submitted to South Coast AQMD CEQA for approval prior to the start of construction. At a minimum the Construction Emission Management Plan would include the following types of mitigation measures.

AQ-2 All construction equipment must be tuned and maintained in compliance with the manufacturer's recommended maintenance schedule and specifications that optimize emissions without nullifying engine warranties. All maintenance records for each equipment and their construction contractor(s) should be made available for inspection and remain onsite for a period of at least two years from completion of construction.

AQ-3 Survey and document the proposed project's construction areas and identify all construction areas that are served by electricity. Onsite electricity, rather than temporary power generators, shall be used in all construction areas that are demonstrated to be served by electricity. This documentation shall be provided as part of the Construction Emissions Management Plan.

AQ-4 Require construction equipment such as concrete/industrial saws, pumps, aerial lifts, material hoist, air compressors, forklifts, excavator, wheel loader, and soil compactors be electric or alternative-fueled (i.e., non-diesel).

AQ-5 All off-road diesel-powered construction equipment greater than 50 hp shall meet Tier-4 off-road emission standards at a minimum. In addition, if not already supplied with a factory-equipped diesel particulate filter, all construction equipment shall be outfitted with Best Available Control Technology (BACT) devices certified by CARB. Any emissions control device used by the contractor shall achieve emissions reductions that are no less than what could be achieved by a Level 3 diesel emissions control strategy for a similarly sized engine as defined by CARB regulations. Construction equipment shall incorporate, where feasible, emissions-reducing technology such as hybrid drives and specific fuel economy standards. In the event that any equipment required under this mitigation measure is not available, the project proponent shall provide documentation in the Construction Emissions Management Plan or associated subsequent status reports as information becomes available.

AQ-6 Suspend use of all construction activities that generate air pollutant emissions during first stage smog alerts.

If, at the time when each facility-specific project is proposed in response to the proposed project, that improved emission reduction technologies become available for on- and off-road construction equipment, as part of the CEQA evaluation for the facility-specific project, the construction mitigation measures will be updated accordingly.

Implementing Parties: The South Coast AQMD's Governing Board finds that implementing the mitigation measures AQ-1 through AQ-6 is the responsibility of the owner, operator, or agent of each affected facility who submits a permit application to comply with the proposed project.

Monitoring Agency: The South Coast AQMD's Governing Board finds that, through its discretionary authority to issue and enforce permits for this project, the South Coast AQMD will ensure compliance with mitigation measures AQ-1 through AQ-6. Mitigation monitoring and reporting (MMR) will be accomplished as follows:

MMRAQ-1: Construction Emission Management Plan
Each facility operator shall develop and submit a Construction Emission Management Plan to the South Coast AQMD for approval prior to starting construction activities. Upon approval, each facility operator shall train all personnel subject to the requirements set forth in the Construction Emission Management Plan on how to comply with the requirements in the plan, and document that training. The South Coast AQMD may conduct routine inspections of the site to verify compliance. The Construction Emission Management Plan shall include, at a minimum, the following information:

- A construction schedule of activities for each construction phase that indicates the number of construction workers needed, and the type, fuel source, and number of construction equipment needed for each construction phase;
- A description of truck routing with a priority given to consolidating truck deliveries and scheduling deliveries to avoid peak hour traffic conditions;
- A format or system for logging delivery dates, times, and type of deliveries;
- A description of entry/exit points to the construction site;
- An identification of parking locations at the construction site; and,
- A description of how the prohibition of truck idling in excess of five consecutive minutes or another time-frame as allowed by the CCR Title 13 Section 2485, will be conveyed to truck drivers.

Traffic Control
Traffic requiring entrance onto each facility's property will be directed toward the entry gate or gates, if there are multiple entrances, so that congestion, as well as associated air pollution, will be minimized.

Points of entry will be selected to maximize facility security and reduce traffic-associated emissions. Each facility operator will direct their Receiving Department to consider delivery items, time of delivery, in-plant congested areas, surrounding area traffic, and gate security issues when assigning a gate entry location.

On-site parking will be used to the maximum extent available. In the event that off-site parking is required, construction workers may be requested to park at a designated off-site property. Buses or some other type of shuttle may transfer multiple workers at one time to and from the project site. No on-street parking (i.e., off of each facility's site) will be allowed.

Each facility operator will limit the number of personal and company vehicles allowed to enter each facility beyond the parking lots. This restriction helps minimize onsite emissions and promotes the use of ride sharing and alternate fueled transportation such as bicycles and electric golf carts.

Construction Schedule

In an effort to reduce traffic by construction workers, operators of each facility may request its contractors to follow a compressed workweek. An example of a compressed workweek would be a four-day work week and a 10-hour workday with most work scheduled to begin by 7:00 a.m. and end after 5:30 p.m., Monday through Friday, to further minimize traffic congestion and related emissions. In addition, some work may need to be scheduled during the night shift, which will begin after 6:00 p.m. and end around 4:30 a.m. Critical path work may require a deviation from the aforementioned workweek and start- and stop-times; however, deviations will be minimized.

During process unit shutdowns, extended work shifts and night shifts, scheduled six to seven days per week, may be necessary. Each facility operator will establish in their Construction Emission Management Plan the details of the construction schedule, including operating hours, days, and number of shifts per day. This construction work schedule will need to be designed to minimize the travel time during peak travel periods.

Trip Reduction Plan

No feasible mitigation has been identified for the emissions from on-road vehicle trips. CEQA Guidelines Section 15364 defines feasible as "...capable of being accomplished in a successful manner." No feasible mitigation measures for offsite motor vehicles have been identified. Health and Safety Code Section 40929 prohibits the air districts and other public agencies from requiring an employee trip reduction program making such mitigation infeasible.

Delivery of Equipment and Materials

Each facility operator will coordinate the delivery of equipment and materials to avoid peak hour traffic, whenever possible. That is, delivery of construction materials to the site will be scheduled to occur during off-peak periods which are typically from 8:30 a.m. until 4:00 p.m. Monday through Friday. Each facility operator will request that equipment and material deliveries be minimized between the hours of 7:00 a.m. to 8:00 a.m. and 4:30 p.m. to 5:30 p.m. to reduce traffic in and out of each facility during high traffic peak times. Exceptions will be made for trucks carrying time-critical materials, e.g., concrete delivery and soil hauling (which eliminates the double handling or on-site stock-piling of soil, preventing it from being moved from place-to-place due to lack of adequate staging area, and subsequent removal at a later time via trucks). Delivery routes and schedules will be developed pursuant to the California Department of Transportation regulations.

It may be necessary to handle a limited amount of equipment as wide or special loads. These deliveries are subject to California Department of Transportation regulations and will be coordinated with local police departments. These trips will be scheduled to avoid peak hour traffic.

Prohibit Trucks From Idling Longer Than Five Minutes
Each facility operator will notify all vendors that during deliveries, truck idling time will be limited to no longer than five minutes or another time-frame as allowed by the California Code of Regulations, Title 13 Section 2485 - CARB's Airborne Toxic Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling. For any delivery that is expected to take longer than five minutes, each facility operator will require the truck's operator to shut off the engine. Each facility operator will notify the vendors of these delivery requirements at the time that the purchase order is issued and again when trucks enter the gates of the facility. To further ensure that drivers understand the truck idling requirement, signs will be posted at each facility entry gates stating idling longer than five minutes is not permitted.

MMRAQ-2: Maintain Construction Equipment, Tuned Up to Manufacturer's Recommended Specifications That Optimize Emissions Without Nullifying Engine Warranties

Each facility operator, in cooperation with the construction contractors, will maintain vehicle and equipment maintenance records for the construction portion of the proposed project. All construction vehicles must be maintained in compliance with the manufacturer's recommended maintenance schedule. Each facility operator will maintain their construction equipment and the construction contractor will be responsible for maintaining their equipment and maintenance records. All maintenance records for each facility and their construction contractor(s) will remain on-site for a period of at least two years from completion of construction.

MMRAQ-3: Survey of Construction Areas Where Electricity is Available for Operating Electric On-Site Mobile Equipment

Each facility operator and/or their construction contractor(s) will conduct a survey of the proposed project construction area(s) to assess whether the existing infrastructure can provide access to electricity, as available, within the facility or construction site, in order to operate electric on-site mobile equipment. For example, each facility operator and/or their construction contractor(s) will assess the number of electrical welding receptacles available.

Construction areas within the facility or construction site where electricity is and is not available must be clearly identified on a site plan as part of the Construction Emission Management Plan. The use of non-electric onsite mobile equipment shall be prohibited in areas of the facility that are shown to have access to electricity. The use of electric on-site mobile equipment within these identified areas of the facility or construction site will be allowed.

Each facility operator shall include in all construction contracts the requirement that the use of non-electric on-site mobile equipment is prohibited in certain portions of the facility as identified on the site plan. Each facility operator shall maintain records that indicate the location within the facility or construction site where all electric and non-electric on-site mobile equipment are operated, if at all, for a period of at least two years from completion of construction.

MMRAQ-4: Use Electricity or Alternate Fuels for On-Site Mobile Equipment Instead of Diesel Equipment to the Extent Feasible

Each facility operator and/or their construction contractor(s) shall evaluate the use of electricity and alternate fuels for on-site mobile construction equipment prior to the commencement of construction activities, provided that suitable equipment is available for the activity. Equipment vendors will be contacted to determine the commercial availability of electric or alternate-fueled construction equipment. Priority should be given to the use of electric on-site mobile construction equipment. If electricity is not available, then use alternative fuels to power on-site mobile construction equipment where feasible. Equipment that will use electricity or alternate fuels will be included in the Construction Emission Management Plan.

The potential equipment that may be considered includes, but is not limited to:

- Electric welders
- Electric scissor lifts
- Electric golf carts
- Bicycles
- Electric or bi-powered boom lifts

MMRAQ-5: All Off-Road Diesel-Powered Construction Equipment Greater Than 50 hp Shall Meet Tier 4 Off-Road Emission Standards and Shall Be Equipped With CARB-Certified Best Available Control Technology (BACT) Emissions Control Devices

Each facility operator shall include in all construction contracts the requirement that all off-road diesel-powered construction equipment greater than 50 hp shall meet Tier-4 off-road emission standards at a minimum. In addition, if not already supplied with a factory-equipped diesel particulate filter, all construction equipment shall be outfitted with Best Available Control Technology (BACT) devices certified by CARB. Any emissions control device used by the contractor shall achieve emissions reductions that are no less than what could be achieved by a Level 3 diesel emissions control strategy for a similarly sized engine as defined by CARB regulations. In addition, construction equipment shall incorporate, where feasible, emissions savings technology such as hybrid drives and specific fuel economy standards. In the event that any equipment required under this mitigation measure is not available, the project proponent shall provide documentation in the Construction

Emissions Management Plan or associated subsequent status reports as information becomes available.

MMRAQ-6: Suspend All Construction Activities That Generate Air Emissions During First Stage Smog Alerts
If and when any first stage smog alert or greater occurs, each facility operator will record the date and time of each alert, will suspend all construction activities that generate emissions, and will record the date and time when the use of construction equipment and construction activities are suspended. This log shall be maintained on-site for a period of at least two years from completion of construction.

B. GHG Impacts

Impacts Summary: The proposed project is expected to decrease the severity of the overall GHG emission impacts that were previously examined under the December 2015 Final PEA for NOx RECLAIM, but the total projected increase of GHG emissions exceed the South Coast AQMD air quality significance threshold of 10,000 MTCO2e/yr for GHGs. Therefore, the proposed project is considered to have significant and unavoidable adverse GHG impacts, and the Final SEA contains feasible measures which could minimize the significant adverse impacts. The following mitigation measures are intended to minimize the GHG emissions associated with water conveyance. No feasible mitigation measures have been identified to reduce GHG emissions to a less than significant levels.

Mitigation Measures: The following mitigation measures will apply to any facility whose operator chooses to install NOx control equipment that utilizes water for its operation. South Coast AQMD staff will conduct a CEQA evaluation of each facility-specific project proposed in response to the proposed project and determine if the project is covered by the analysis in the Final SEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing South Coast AQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by South Coast AQMD personnel.

GHG-1: When NOx control equipment is installed and water is required for its operation, the facility operator is required to use recycled water, if available, to satisfy the water demand for the NOx control equipment.

GHG-2: In the event that recycled water cannot be delivered to the affected facility, the facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be supplied to the project.

Implementing Parties: The South Coast AQMD's Governing Board finds that implementing mitigation measures GHG-1 through GHG-2 is the responsibility of the owner, operator, or agent of each affected facility who submits a permit application to comply with the proposed project.

Monitoring Agency: The South Coast AQMD's Governing Board finds that through its discretionary authority to issue and enforce permits for this project, the South Coast AQMD will ensure compliance with mitigation measures GHG-1 through GHG-2. Mitigation monitoring and reporting (MMR) will be accomplished as follows:

MMRGHG-1: Use Recycled Water, If Available, for NOx Control Equipment That Requires Water for Its Operation

At the time of submitting an application for a Permit to Construct for NOx control equipment and water is required for its operation, each facility operator shall submit a copy of a Memorandum of Understanding agreement reached between the facility operator and the recycled water supplier or purveyor that indicates recycled water will be used to supply water to the NOx control equipment. Once the NOx control equipment becomes operational, on a monthly basis, each facility operator will record the amount of recycled water delivered to the NOx control equipment from the recycled water bill. This log shall be maintained on-site for a period of at least two years from initiating operation.

MMRGHG-2: Submit Written Declaration if Recycled Water is Not Available

The facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project.

C. Hazards and Hazardous Materials Impacts Due to Use and Storage of Ammonia

Impacts Summary: Installation of new SCRs and associated ammonia storage tanks and the upgrades of existing SCRs as a result of implementing the proposed project will be expected to comply with applicable design codes and regulations, conform to National Fire Protection Association standards, and conform to regulations or generally accepted industry practices related to operating policy and procedures concerning the design, construction, security, leak detection, spill containment or fire protection. However, the proposed project is expected to generate significant adverse hazards and hazardous materials impacts for the routine transport, use, and storage of ammonia. However, even though hazards associated with ammonia are significant, it should be noted that the incremental amount of ammonia that is expected to be needed to implement the proposed project is substantially less than what was previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Regarding the handling of fresh and spent catalyst, since SCR catalysts are not hazardous, the proposed project is expected to generate less than significant hazards and hazardous materials impacts since SCR catalysts are not hazardous. To the extent that future projects to install new or modify existing NOx controls conforms with the hazard analysis in the Final SEA, no further hazard analysis may be necessary. However, if site-specific characteristics are involved with future projects that are outside the scope of this analysis, further hazards analysis may be warranted.

Mitigation Measures: The following mitigation measures will apply to any facility whose operator chooses to install a new SCR system and the accompanying ammonia storage tank for combustion equipment subject to NOx emission standards in PR 1109.1. South Coast

AQMD staff will conduct a CEQA evaluation of each facility-specific project proposed in response to the proposed project and determine if the project is covered by the analysis in this PEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing South Coast AQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by South Coast AQMD personnel.

HZ-1: Require the use of aqueous ammonia at concentrations less than 19 percent by weight.

HZ-2: Install safety devices, including but not limited to: continuous tank level monitors (e.g., high and low level), temperature and pressure monitors, leak monitoring and detection system, alarms, check valves, and emergency block valves.

HZ-3: Install secondary containment such as dikes and/or berms to capture 110 percent of the storage tank volume in the event of a spill.

HZ-4: Install a grating-covered trench around the perimeter of the delivery bay to passively contain potential spills from the tanker truck during the transfer of aqueous ammonia from the delivery truck to the storage tank.

HZ-5: Equip the truck loading/unloading area with an underground gravity drain that flows to a large on-site retention basin to provide sufficient ammonia dilution to minimize the offsite hazards impacts to the maximum extent feasible in the event of an accidental release during transfer of aqueous ammonia.

HZ-6: Install tertiary containment that is capable of evacuating 110 percent of the storage tank volume from the secondary containment area.

Implementing Parties: The South Coast AQMD's Governing Board finds that implementing mitigation measures HZ-1 through HZ-6 is the responsibility of the owner, operator, or agent of each affected facility who submits a permit application to comply with the proposed project.

Monitoring Agency: The South Coast AQMD's Governing Board finds that through its discretionary authority to issue and enforce permits for this project, the South Coast AQMD will ensure compliance with mitigation measures HZ-1 through HZ-6. Mitigation monitoring and reporting (MMR) will be accomplished as follows:

MMRHZ-1: Require Use of Aqueous Ammonia at Concentrations Less than 19 Percent by Weight

For any facility seeking to install a new ammonia storage tank for a new SCR to control combustion equipment subject to the NOx emission standards in PR 1109.1, a permit application will need to be submitted. The South Coast AQMD will issue permit conditions requiring the use of aqueous ammonia no greater than 19 percent by weight.

MMRHZ-2: Install Safety Devices Including but Not Limited to: Continuous Tank Level Monitors, Temperature and Pressure Monitors, Leak Monitoring and Detection System, Alarms, Check Valves, and Emergency Block Valve

MMRHZ-3: Install Secondary Containment to Capture 110 Percent of the Storage Tank Volume

MMRHZ-4: Install a Grating-Covered Trench Around the Perimeter of the Delivery Bay

MMRHZ-5: Equip the Truck Loading/Unloading Area with an Underground Gravity Drain that Flows to a Large On-Site Retention Basin to Provide Sufficient Ammonia Dilution

MMRHZ-6: Install Tertiary Containment that is Capable of Evacuating 110 Percent of the Storage Tank Volume from the Secondary Containment Area

Each facility operator shall develop and submit a blueprint with locations of secondary containment, tertiary containment, and safety devices around the proposed ammonia storage tank site; and locations of a grating-covered trench and underground gravity drain system for the truck loading/unloading area. The blueprint must be submitted to the South Coast AQMD for approval prior to starting construction activities. Following approval, the South Coast AQMD must be notified of any changes to the construction plans, and the South Coast AQMD may conduct inspections of the site to verify compliance.

D. Water Demand Impacts

Impacts Summary - Hydrotesting: The proposed project makes more severe, the water demand impacts due to hydrotesting previously analyzed under the December 2015 Final PEA for NOx RECLAIM. Some NOx control equipment may require the installation of support equipment such as storage tanks, for example, which need to undergo hydrotesting in order to verify the structural integrity prior to operation. Because hydrotesting can utilize a substantial amount of water, significant adverse impacts associated with water demand during hydrotesting are expected from the proposed project post-construction but prior to operation. For any facility that installs NOx control equipment that also requires the installation of support equipment, such as a storage tank or other equipment, to be installed and hydrotested as part of the proposed project, the use of non-potable water such as recycled water or diverted process water can help substantially reduce the water demand impacts to a less than significant level if facility operators that have access to recycled water or diverted non-potable process water are required to use recycled water or diverted non-potable process water.

Even though the previous water demand analysis in the December 2015 Final PEA for NOx RECLAIM showed that there was a sufficient supply of both potable and recycled water available at the time the CEQA document was certified, because the project-specific water demand impacts have been concluded to be significant due to the uncertainty of the ability for some facilities to receive recycled water and in consideration of California's on-going drought, the potential water demand impacts continue to be cumulatively considerable pursuant to CEQA Guidelines Section 15064(h)(1).

Because there are significant adverse water demand impacts from the proposed project post-construction but prior to operation during hydrotesting of support equipment, the SEA must describe feasible measures which could minimize the significant adverse impacts for hydrotesting activities. The following mitigation measures are intended to minimize the amount of potable water used for hydrotesting by requiring either recycled water or other non-potable water as a substitute, but the potable water demand may not necessarily be reduced to less than significant levels and the overall effectiveness of the mitigation measures is dependent upon whether each facility has access to these alternate water sources.

Mitigation Measures for Hydrotesting: The following water demand mitigation measures are required during hydrotesting for any facility that installs NOx control equipment with support equipment that requires hydrotesting prior to its operation as part of the proposed project. South Coast AQMD staff will conduct a CEQA evaluation of each facility-specific project proposed in response to the proposed project and determine if the project is covered by the analysis in this PEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing South Coast AQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by South Coast AQMD personnel.

HWQ-1 When support equipment such as a storage tank or other equipment is installed to support operations of installed NOx control equipment and hydrotesting is required prior to operation, the facility operator is required to use, in lieu of potable water, recycled water or other non-potable process water temporarily diverted from elsewhere within the facility, if available, to satisfy the water demand for hydrotesting.

HWQ-2 For hydrotesting purposes, in the event that recycled water cannot be delivered to the affected facility and diverted non-potable process water is not used, the facility operator is required to submit two written declarations with each application for a Permit to Construct for the NOx control equipment and any support equipment such as storage tank or other equipment that requires hydrotesting, one to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project and one from a high-ranking officer at the facility indicating the reason(s) and the supporting evidence that explains why the non-potable process water cannot be diverted to the project from elsewhere within the facility.

Impacts Summary – Operation of NOx Control Equipment: While the proposed project will be expected to install additional new SCRs and upgrade existing SCRs, and replace existing burners with ULNBs, when compared to the previous analysis the December 2015 Final PEA for NOx RECLAIM, since SCR and ULNB technology do not utilize water for their operation, no increases in operational water are anticipated as a result of these changes. Also, while the proposed project may involve the installation of LoTOx™ with WGSs, which utilize water for their operation, these NOx control devices and the associated water use were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Moreover, the proposed project neither contains any changes to the type of combustion equipment that would utilize LoTOx™ with WGSs nor requires any updates to the amount of water use that will be needed for their operation. Thus, an updated hydrology analysis of scrubber-related impacts was not required for the Final SEA. Since significant adverse water demand impacts during operation were concluded for the previously proposed project analyzed the December 2015 Final PEA for NOx RECLAIM, the analysis in the Final SEA is also concluding significant adverse water demand impacts during operation.

Mitigation Measures for Operations of NOx Control Equipment That Utilizes Water: The following water demand mitigation measures are required during operation of any WGS or any other type of NOx control equipment that utilizes water for its operation that is installed as part of the proposed project.

HWQ-3 When NOx control equipment is installed and water is required for its operation, the facility operator is required to use recycled water, if available, to satisfy the water demand for the NOx control equipment.

HWQ-4 In the event that recycled water cannot be delivered to the affected facility, the facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project.

Implementing Parties: The South Coast AQMD's Governing Board finds that implementing the mitigation measures HWQ-1 through HWQ-4 is the responsibility of the owner, operator, or agent of each affected facility who submits a permit application to comply with the proposed project.

Monitoring Agency: The South Coast AQMD's Governing Board finds that through its discretionary authority to issue and enforce permits for this project, the South Coast AQMD will ensure compliance with mitigation measures HWQ-1 through HWQ-4. Mitigation monitoring and reporting (MMR) will be accomplished as follows:

MMRHWQ-1: USE RECYCLED WATER OR OTHER NON-POTABLE PROCESS WATER, IF AVAILABLE, FOR HYDROTESTING

At the time of submitting an application for a Permit to Construct for NOx control equipment and any support equipment such as storage tank or other equipment that requires hydrotesting, each facility operator shall submit one of the following: 1) a copy of a Memorandum of Understanding agreement reached between the facility operator and the recycled water supplier or purveyor that indicates recycled water will be used to supply water to conduct hydrotesting; or, 2) a supplement to the application(s) that describes how other non-potable process water will be diverted for hydrotesting. Once hydrotesting is complete, each facility operator will record one of the following: 1) the amount of recycled water delivered for hydrotesting from the recycled water bill; or 2) the amount of diverted process water used for hydrotesting. This log shall be maintained on-site for a period of at least two years from conducting hydrotesting.

MMRHWQ-2: SUBMIT WRITTEN DECLARATION IF RECYCLED WATER AND OTHER NON-POTABLE PROCESS WATER IS NOT USED FOR HYDROTESTING

The facility operator is required to submit two written declarations with the application for a Permit to Construct for the NOx control equipment and any support equipment such as a storage tank or other equipment that requires hydrotesting, one to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project and one from a high-ranking officer at the facility indicating the reason(s) and the supporting evidence that explains why the non-potable process water cannot be diverted to the project from elsewhere within the facility.

MMRHWQ-3: USE RECYCLED WATER, IF AVAILABLE, FOR NOX CONTROL EQUIPMENT THAT REQUIRES WATER FOR ITS OPERATION

At the time of submitting an application for a Permit to Construct for NOx control equipment that requires water for its operation, each facility operator shall submit a copy of a Memorandum of Understanding agreement reached between the facility operator and the recycled water supplier or purveyor that indicates recycled water will be used to supply water to the NOx control equipment. Once the NOx control equipment becomes operational, on a monthly basis, each facility operator will record the amount of recycled water delivered to the NOx control equipment from the recycled water bill. This log shall be maintained on-site for a period of at least two years from initiating operation.

MMRHWQ-4: SUBMIT WRITTEN DECLARATION IF RECYCLED WATER IS NOT AVAILABLE FOR NOX CONTROL EQUIPMENT THAT REQUIRES WATER FOR ITS OPERATION

The facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project.

7.1 Mitigation, Monitoring and Reporting Plan Conclusion

Based on a "worst-case" analysis, the potential adverse construction air quality impacts, GHG impacts, hazards and hazardous materials impacts due to routine transport, use, and storage of ammonia, and water demand impacts from the adoption and implementation of the proposed project are considered significant and unavoidable. Feasible mitigation measures have been identified for construction air quality impacts, GHG impacts, hazards and hazardous materials impacts due to use and storage of ammonia, and water demand impacts that would reduce these impacts associated with the proposed project; however, the mitigation measures are not sufficient to reduce the impacts to less than significant levels. No feasible mitigation measures have been identified to help minimize the potentially significant adverse impacts to hazards and hazardous materials due to routine transport of ammonia.

Further, none of the alternatives analyzed would reduce the construction air quality impacts, GHG impacts, hazards and hazardous materials impacts due to deliveries of ammonia, and hydrology impacts to less than significant levels. As a result, no other feasible mitigation measures or project alternatives have been identified that would further reduce these impacts while still achieving the overall objectives of the proposed project.

8.0 Record of Proceedings

For purposes of CEQA, including the Findings, Statement of Overriding Considerations, and the Mitigation, Monitoring and Reporting Plan, the Record of Proceedings for the proposed project consists of the following documents and other evidence, at a minimum:

- The Final SEA for the proposed project, including appendices and technical studies included or referenced in the Final SEA, and all other public notices issued by South Coast AQMD for the Final SEA.
- The Draft SEA for the proposed project including appendices and technical studies included or referenced in the Draft SEA, and all other public notices issued by South Coast AQMD for the Draft SEA.
- All written comments submitted by agencies or members of the public during the public review comment period on the Draft SEA.
- All responses to written comments submitted by agencies or members of the public during the public review comment period on the Draft SEA.
- All written and verbal public testimony presented during a noticed public hearing for the proposed project.
- The reports and technical memoranda included or referenced in the Response to Comments.
- All documents, studies, EIRs/EAs, or other materials incorporated by reference and tiered-off in the Draft SEA and Final SEA.
- The Resolution adopted by South Coast AQMD in connection with the proposed project, and all documents incorporated by reference therein, including comments received after the close of the public review and comment period and responses thereto.
- Matters of common knowledge to South Coast AQMD, including but not limited to federal, state, and local laws and regulations.
- Any documents expressly cited in the Findings, Statement of Overriding Considerations, and the Mitigation, Monitoring and Reporting Plan.
- Any other relevant materials required to be in the record of proceedings by Public Resources Code Section 21167.6(e).
- The Notice of Decision, prepared in compliance with Public Resources Code Section 21080.5(d)(2)(E), CEQA Guidelines Section 15252(b), and South Coast AQMD Rule 110(f), if the Governing Board certifies the Final SEA and approves the approved project.

To comply with CEQA Guidelines Section 15091(e), the South Coast AQMD specifies the Deputy Executive Officer of the Planning, Rule Development, and Area Sources Division as the custodian of the administrative record for the proposed project, which includes the documents or other materials which constitute the record of proceedings upon which the South Coast AQMD's actions related to the proposed project is based, and which are located at the South Coast AQMD headquarters, 21865 Copley Drive, Diamond Bar, California 91765. Copies of these documents, which constitute the record of proceedings, are and at all relevant times have been and will be available upon request. This information is provided in accordance with Public Resources Code Section 21081.6 (a)(2) and CEQA Guidelines Section 15091(e).

APPENDIX A

November 2015 Attachment 1 to the Governing Board Resolution for Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM): Findings, Statement of Overriding Considerations, and Mitigation Monitoring Plan

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Attachment 1 to the Governing Board Resolution for:
Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

Findings, Statement of Overriding Considerations, and Mitigation Monitoring Plan

SCAQMD No. 12052014BAR
State Clearinghouse No: 2014121018

November 2015

Executive Officer
Barry R. Wallerstein, D. Env.

Deputy Executive Officer
Planning, Rule Development and Area Sources
Philip Fine, Ph.D.

Assistant Deputy Executive Officer
Planning, Rule Development and Area Sources
Jill Whynot

Author:	Barbara Radlein	Program Supervisor, CEQA Special Projects
Reviewed By:	Ian MacMillan	Planning and Rules Manager, Planning, Rule Development, and Area Sources
	Joe Cassmassi	Director of Strategic Initiatives, Planning, Rule Development, and Area Sources
	Gary Quinn, P.E.	Program Supervisor, Planning, Rule Development, and Area Sources
	Barbara Baird	Chief Deputy Counsel
	William Wong	Principal Deputy District Counsel
	Karin Manwaring	Senior Deputy District Counsel

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ATTACHMENT 1 TO THE GOVERNING BOARD RESOLUTION FOR: FINAL PROGRAM ENVIRONMENTAL ASSESSMENT FOR PROPOSED AMENDED REGULATION XX – REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)

FINDINGS, STATEMENT OF OVERRIDING CONSIDERATIONS, AND MITIGATION MONITORING PLAN

INTRODUCTION

The proposed amendments to Regulation XX - Regional Clean Air Incentives Market (RECLAIM) are considered a "project" as defined by the California Environmental Quality Act (CEQA) (California Public Resources Code §§21000 et seq.). The SCAQMD as Lead Agency for the proposed project, prepared a Notice of Preparation/Initial Study (NOP/IS) which identified environmental topics to be analyzed in a Draft Program Environmental Assessment (PEA). The NOP/IS provided information about the proposed project to other public agencies and interested parties prior to the intended release of the Draft PEA. The NOP/IS was distributed to responsible agencies and interested parties for a 57-day public review and comment period from December 5, 2014 to January 30, 2015. The initial evaluation in the NOP/IS identified the topics of aesthetics; air quality and greenhouse gas emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic, as potentially being significantly adversely affected by the project. Since the proposed project may have statewide, regional or areawide significance, a CEQA scoping meeting is required and was held for the proposed project pursuant to Public Resources Code §21083.9 (a)(2) on January 8, 2015. Eight comment letters were received from the public regarding the preliminary analysis in the NOP/IS. None of these comment letters identified other potentially significant adverse impacts from the proposed project that should be analyzed in the PEA.

The Draft PEA was released for a 53-day public review and comment period from August 14, 2015 to October 6, 2015 and further analyzed whether or not the potential adverse impacts to the environmental topic areas identified in the NOP/IS are significant. The Draft PEA concluded that only the topics of air quality and greenhouse gases (GHGs), hydrology (water demand), and, hazards and hazardous materials (due to ammonia transportation) would have significant adverse impacts. The Draft PEA included the NOP/IS (in Appendix F), the comment letters received relative to the NOP/IS and responses to individual comments (in Appendix G), and a summary of comments made at the CEQA scoping meeting and responses to individual comments (in Appendix H).

Eight comment letters were received during the public comment period on the analysis presented in the Draft PEA. Responses to these comment letters have been prepared and are included in Appendix I of the Final PEA The Final PEA, prepared pursuant to CEQA Guidelines §15132, identifies air quality and GHGs, hydrology (water demand), and, hazards and hazardous materials (due to ammonia transportation) as areas that may be adversely affected by the proposed project.

In addition to incorporating the comment letters and the responses to comments, some modifications have been made to the Draft PEA to make it a Final PEA. SCAQMD staff evaluated these modifications and concluded that none of the modifications alter any conclusions reached in the Draft PEA, nor do they constitute significant new information[1] and, therefore, do not require recirculation of the document pursuant to CEQA Guidelines §§15073.5 and 15088.5. The Final PEA will be presented to the Governing Board prior to its December 4, 2015 public hearing.

SUMMARY OF THE PROPOSED PROJECT

To comply with the requirements in Health and Safety Code §40440 by conducting a Best Available Retrofit Control Technology (BARCT) assessment, SCAQMD staff is proposing amendments to the following rules which are part of Regulation XX – Regional Clean Air Incentives Market (RECLAIM): Rule 2001 – Applicability; Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx); Rule 2005 – New Source Review For RECLAIM; Attachment C from Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Sulfur (SOx) Emissions; and, Attachment C from Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Nitrogen (NOx) Emissions. The proposed amendments to Regulation XX would reduce emissions from equipment and processes operated at NOx RECLAIM facilities located throughout the entire SCAQMD jurisdiction. In particular, the environment could be impacted from the proposed project due to facilities installing new, or modifying existing control equipment for the following types of equipment/source categories in the NOx RECLAIM program: 1) fluid catalytic cracking units; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) sulfur recovery units – tail gas treatment units; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant internal combustion engines; 8) container glass melting furnaces; 9) coke calcining; and, 10) metal heat treating furnaces. For clarity and consistency throughout the regulation, other minor revisions are also proposed.

The proposed project is expected to result in a total of 14 tons per day (tpd) of reduction of NOx RECLAIM Trading Credits (RTCs) from the current 2015 RTC holdings of 26.5 tpd over a seven-year period from 2016 to 2022. The 14 tpd of NOx RTC reductions will be reduced from the allocations of 56 facilities plus the investors that, together, hold 90 percent of the NOx RTC holdings. Investors are included in the refinery sector and treated as one facility. For the remaining 219 facilities that hold 10 percent of the 26.5 tpd of the NOx RTCs, no NOx RTC

[1] Pursuant to CEQA Guidelines §§ 15073.5 and 15088.5, circumstances that would require recirculation include, for example, any of the following:
(1) A new, avoidable significant effect would result from the project or from a new mitigation measure proposed to be implemented, or new mitigation measures or project revisions must be added in order to reduce the effect to insignificance.
(2) The proposed mitigation measures or project revisions will not reduce the effects to less than significance and new measures or revisions are required.
(3) A substantial increase in the severity of an environmental impact would result unless mitigation measures are adopted that reduce the impact to a level of insignificance.
(4) A feasible project alternative or mitigation measure considerably different from others previously analyzed would clearly lessen the environmental impacts of the project, but the project's proponents decline to adopt it.
(5) The draft CEQA document was so fundamentally and basically inadequate and conclusory in nature that meaningful public review and comment were precluded.

shave is proposed because either no new BARCT (not cost effective and/or infeasible) was identified, or gains in emission reductions would be negligible, for the types of equipment and source categories at these facilities. By following this approach, the shave is distributed as follows:

- 66% shave for 9 refineries and investors (treated as one facility)
- 49% shave for 21 electricity generating facilities (EGFs)
- 49% shave for 26 non-major facilities
- 0% shave for 219 remaining facilities

In addition, the overall NOx RTC reductions of 14 tpd are expected to be achieved incrementally from 2016 to 2022, according to the following implementation schedule:

- 2016 – 4 tons per day
- 2018 – 2 tons per day
- 2019 – 2 tons per day
- 2020 – 2 tons per day
- 2021 – 2 tons per day
- 2022 – 2 tons per day

POTENTIAL SIGNIFICANT ADVERSE IMPACTS THAT CANNOT BE REDUCED BELOW A SIGNIFICANT LEVEL

The Final PEA identified the topics of air quality (during construction) and GHGs (from combined construction and operation activities), hydrology (due to water demand), and, hazards and hazardous materials (due to ammonia transportation) as the only areas that may be significantly adversely affected by the proposed project. Since the release of the Draft PEA for public review and comment, the operators of one refinery have indicated plans to shut down one fluid catalytic cracking unit (FCCU) in 2017. Thus, the projected installation of wet gas scrubber (WGS) technology is expected to only occur at one of the two FCCUs. Further, since the release of the Draft PEA for public review and comment, the number of selective catalytic reduction (SCR) units that may be installed for the refinery boiler and heater source category has been lowered to 73 units, instead of 74. Thus, the analysis in this PEA for the refinery sector is conservative as it overestimates the potentially significant adverse impacts that cannot be reduced below a significant level for the following environmental topics.

<u>Air Quality Impacts During Construction</u>

Relative to construction emissions, the "worst-case" scenario is when construction activities overlap due to concurrent construction activities occurring at a single facility and at multiple facilities. Specifically, the scenario analyzed in the Final PEA is the simultaneous activities of demolishing existing equipment, site preparation, and constructing new or modifying existing air pollution control equipment, which could occur at a single facility or at more than one facility. The analysis further assumes that the "worst-case" day is that in which each construction project is operating construction equipment that generates the greatest emissions.

Based on these assumptions for overlapping construction activities, the "worst-case" emissions were calculated to be: 429 pounds per day of volatile organic compounds (VOC); 1,656 pounds per day of NOx; 2,745 pounds per day of carbon monoxide (CO); 3 pounds per day of oxides of sulfur (SOx); 1,758 pounds per day before mitigation and 853 pounds per day after mitigation of particulate matter with an aerodynamic diameter less than 10 microns (PM10), respectively; and, 883 pounds per day before mitigation and 430 pounds per day after mitigation of particulate matter with an aerodynamic diameter less than 2.5 microns (PM2.5), respectively. The significance thresholds for construction-related emissions are: 75 pounds per day of VOC; 100 pounds per day of NOx; 550 pounds per day of CO; 150 pounds per day of SOx; 150 pounds per day of PM10; and 55 pounds per day of PM2.5. (Estimated construction emissions did not exceed the significance threshold for SOx.) Because the construction emissions for all of the pollutants except SOx exceed the applicable significance thresholds for construction, mitigation measures are required.

While the air quality mitigation measures for construction that are identified in the Mitigation Monitoring Plan section of this document may reduce construction emissions to the maximum extent feasible, none are mitigation measures that will avoid the significant impacts or reduce the construction air quality impacts to less than significant. Also, no other feasible mitigation measures have been identified to reduce construction air quality emissions to a level of insignificance. Therefore, the proposed project is considered to have significant adverse unavoidable project-specific and cumulative air quality impacts during construction.

Greenhouse Gas Impacts

With regard to GHG emissions, the proposed project involves combustion processes during both construction and operation, which could generate GHG emissions such as carbon dioxide (CO2), methane (CH4), and nitrous oxide (N2O). However, the proposed project does not affect equipment or operations that have the potential to emit non-combustion GHGs such as sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs) or perfluorocarbons (PFCs).

Installation of new or modification of existing NOx control equipment as part of implementing the proposed project is expected to generate construction-related CO2 emissions. In addition, based on the type and size of equipment affected by the proposed project, CO2 emissions from the operation of the NOx control equipment are likely to increase from current levels due to electricity, fuel and water use. The proposed project will also result in an increase of GHG operational emissions produced from additional truck hauling and deliveries necessary to accommodate the additional solid waste generation and increased use of supplies and chemicals such as catalyst and caustic.

For the purposes of addressing the GHG impacts of the proposed project, the overall impacts of CO2 equivalent (CO2e) emissions from the project were estimated and evaluated from the earliest possible initial implementation of the proposed project with construction beginning in 2016. Once the proposed project is fully implemented, the potential NOx emission reductions would continue through the end of the useful life of the equipment. The analysis estimated CO2e emissions from all sources subject to the proposed project (construction and operation) from the beginning of the proposed project (2016) to the end of construction (2022). The beginning of the proposed project was assumed to be no sooner than 2016, since installing NOx control equipment requires planning and engineering in advance. Full implementation of the proposed project is expected to occur by the end of 2022 when the entire 14 tons per day of the NOx RTC shave is completed such that any installed or modified NOx controls could be constructed and operational by this final date. Thus, once construction is complete and the equipment is operational, CO2e emissions will continue to be generated but they will remain constant.

Implementing the proposed project is expected to increase GHG emissions that exceed the SCAQMD's GHG significance threshold for all 11 of the non-refinery facilities and nine refinery facilities, should these facility operators choose to install NOx control technology in response to the proposed project. This potentially significant adverse impact cannot be mitigated below significance. The SCAQMD's GHG significance threshold for industrial sources is 10,000 metric tons of CO2e emissions per year (MTCO2e/yr). While none of the affected facilities individually exceed the GHG industrial significance threshold of 10,000 MTCO2e/yr, the "worst-case" GHG emissions from the proposed project as a whole were calculated to be 41,785 MTCO2e/yr which exceeds the SCAQMD's GHG significance threshold. Thus, the overall GHG emissions exceed the GHG significance threshold and therefore, the proposed project is considered to have significant adverse GHG impacts.

Recycled water projects and the utilization of recycled water are among the most direct ways to reduce GHG from combustion activities associated with conveying water to the affected facilities if water-intensive scrubbers are installed as a result of the proposed project. Specifically, the energy it would take to treat and convey reclaimed water to a facility (e.g., 1,200 kilowatt-hours per million gallons (kWh/MMgallons)[2]) is approximately 10 times less than the amount of energy it would take for potable water (e.g., 12,700 kWh/MMgallons[3]) to be supplied, conveyed and distributed. Thus, for each facility that has access to recycled water and chooses to use recycled water to satisfy the water demands for the proposed project and in turn, mitigate CO2e emissions, less GHG emissions would be generated for the operational water use/conveyance and operational wastewater generation portions of the proposed project. After mitigation, the GHG emissions from the proposed project as a whole were calculated to be 41,100 MTCO2e/yr which still exceeds the SCAQMD's GHG significance threshold.

While the GHG mitigation measures identified in the Mitigation Monitoring Plan section of this document may reduce GHG emissions associated with water conveyance to the maximum extent feasible, none are mitigation measures that will avoid the significant impact or reduce the GHG impact to less than significant. Also, no other feasible mitigation measures have been identified to reduce GHG emissions to a level of insignificance. Therefore, the proposed project is considered to have significant adverse unavoidable cumulative GHG impacts.

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[2] California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005. http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[3] California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005. http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

Water Demand Impacts

Post-Construction/Pre-Operation Activities: Implementation of the proposed project may cause potentially significant adverse water demand impacts associated with hydrotesting equipment post-construction/pre-operation. Specifically, once construction of control equipment and support equipment is completed, but prior to operation of the control equipment, additional water is expected to be used to hydrostatically (pressure) test all storage tanks and pipelines to ensure each structure's integrity. Pressure testing or hydrotesting is typically a one-time event, unless a leak is found.

The analysis in the Final PEA shows that the potential increase in water use for all 20 facilities conducting hydrotesting activities in one day is approximately 353,724 gallons per day which is greater than the SCAQMD's significance threshold of 262,820 gallons per day of potable water. Thus, the amount of potable water that may be used on a daily basis for hydrotesting activities post-construction but prior to operation is potentially significant. However, water used for pressure testing does not have to be of potable quality, but can be recycled water. Alternately, facility operators may substitute the use of purchased recycled water with non-potable water such as treated process water (e.g., cooling tower blowdown water, etc.) that is temporarily re-routed or diverted from elsewhere within the facility. In addition, water used during hydrotesting can be sent somewhere else within a facility for future re-use. Nonetheless, without being able to predict what type of water each facility will use for hydrotesting purposes, the "worst-case" analysis in the Final PEA assumes that 100 percent of potable water could be utilized for hydrotesting purposes and concludes that hydrotesting could cause significant adverse water demand impacts post-construction but prior to operation.

While the use of recycled water may reduce potable water demand during hydrotesting to the maximum extent feasible, the use of recycled water will not avoid the significant impact or reduce the potable water demand impact post-construction but prior to operation to less than significant. Therefore, the proposed project may cause significant potable water demand impacts during hydrotesting post-construction but prior to operation.

Thus, while the mitigation measures that are identified in the Mitigation Monitoring Plan section of this document may reduce potable water demand associated with hydrotesting activities to the maximum extent feasible, the overall effectiveness of the mitigation measures is dependent upon whether each facility has access to either recycled water or other sources of non-potable water. While feasible mitigation measures have been identified to reduce the potable water demand, the potable water demand may not necessarily be reduced to a level of insignificance because of limitations with access to recycled water or other sources of non-potable water. Thus, the proposed mitigation measures may not fully avoid the significant impact or reduce the potable water demand impact to less than significant. Also, no other feasible mitigation measures have been identified to reduce the potable water demand during hydrotesting to a level of insignificance. Therefore, the proposed project is considered to have significant adverse unavoidable cumulative water demand impacts during hydrotesting.

Operation Activities: Implementation of the proposed project may cause potentially significant adverse water demand impacts associated with operating NOx control equipment. Specifically, of the technologies proposed as BARCT for NOx control, only WGSs utilize water. For this reason, only WGS technology was identified as having the potential to generate potentially significant adverse water demand impacts during operation and WGS technology would be BARCT for equipment at seven of the 20 facilities, and all seven of these facilities belong to the refinery sector (e.g., Refineries 1, 2, 4, 5, 6, 8 and 9).

The analysis in the Draft PEA shows that the potential increase in water use for seven facilities that may operate WGSs is approximately 602,814 gallons per day which is greater than the SCAQMD's significance threshold of 262,820 gallons per day of potable water. However, operators of one refinery have indicated plans to shut down one FCCU in 2017. Thus, the installation of WGS technology along with the corresponding increased water demand and wastewater generation projections that were originally contemplated for one of the two FCCUs (e.g., Refineries 4 and 9) are no longer expected to occur. Thus, the potential increase in operational water demand is expected to be less than what was originally analyzed in the Draft PEA. To protect the identity of the refinery in this document, the revised potential increase in operational water demand has been presented as a range in the Final PEA, from 553,499 to 558,978 gallons per day, instead of 602,814 gallons per day.

Of the seven affected refineries, three (e.g., Refineries 1, 5, and 6) currently access recycled water from the Harbor Refineries Recycled Water Pipeline (HRRWP) which is maintained by the Los Angeles Department of Water and Power (LADWP), in conjunction with the West Basin Municipal Water District (WBMWD). The LADWP/WBMWD currently provides 35 million gallons per day (MMgal/day) of recycled water to its customers, which include Refineries 1, 5, and 6. The WBMWD is also in the process of expanding its Hyperion Pump Station to accommodate a throughput of 70 MMgal/day of source water which would result in about 55 to 60 MMgal/day of saleable recycled water if, and when needed to accommodate any increased need by their customers. Thus, should operators of these three refineries commit to utilizing recycled water in lieu of potable water to satisfy the water demand for the NOx control equipment, then the LADWP/WBMWD would be able to supply the additional water (e.g., 398,767 gallons per day or approximately 71 percent of the projected water demand). If these facilities do not utilize recycled water for the proposed project, SCAQMD staff conducted an analysis of potable water supply and concluded that potable water would be available to supply the projected increased water demand at Refineries 1, 5 and 6 (see Final PEA, Chapter 4, Subchapter 4.5 – Hydrology and Water Quality, pp. 4.5-15 to 4.5-20).

Refineries 4, 8, and 9 are not currently connected to the HRRWP to access recycled water. However, Refinery 4 is in the process of finalizing an agreement with WBMWD to acquire 2,240 acre-feet/year (AF/yr)[4] of recycled water (equivalent to two MMgal/day) to replace its current potable water use with recycled water by 2018. In addition, Refineries 4, 8, and 9 are currently in talks with the LADWP and WBMWD to negotiate options for replacing as much as 11,100 AF/yr (equivalent to approximately 9.9 MMgal/day) of current potable water use with

[4] 1 acre-foot = 325,851 gallons

recycled water instead via the HRRWP[5]. Thus, if Refineries 4, 8 and 9 need additional recycled water in response to this proposed project, the LADWP/WBMWD has the capacity to provide additional recycled water as necessary. Again, if these facilities do not obtain access to recycled water for the proposed project, SCAQMD staff conducted an analysis of potable water supply and concluded that potable water would be available to supply the projected increased water demand at Refineries 4, 8 and 9 (see Final PEA, Chapter 4, Subchapter 4.5 – Hydrology and Water Quality, pp. 4.5-15 to 4.5-20).

Refinery 2 is not located near the HRRWP nor any other recycled water pipeline so it is unlikely that Refinery 2 would be able to obtain recycled water should facility operators choose to install a WGS and instead, would need to satisfy the water demand with potable water. According to the LBWD's 2010 UWMP that was prepared in accordance with the California Water Code §10608.20, the potable water delivery projections to their industrial and commercial customers show a long-term projected increase in potable water supply with a slight tapering occurring in years 2030 and 2035 to reflect offsetting by increased deliveries of recycled water to other customers currently being supplied by LBWD with potable water. Based on LBWD's short- and long-term projections for potable water supplies, SCAQMD staff believes that the potential increased water demand of 40,896 gallons per day for Refinery 2 can be accommodated with potable water (see Final PEA, Chapter 4, Subchapter 4.5 – Hydrology and Water Quality, p. 4.5-20).

In addition, it is important to keep in mind that operators of Refinery 2 have two different types of control equipment options available for consideration. As summarized in the PEA (see Tables 1-2 and 1-3 for the petroleum coke calciner source category), the BARCT NOx levels of 10 ppmv corrected for 3% oxygen can be achieved with either a WGS which uses water, or a DGS, which does not. While the analysis in this subchapter considers the technology with the worst-case impacts to water demand and water quality, for Refinery 2, installing WGS technology is not their only option. Should operators choose to install a DGS, instead of a WGS, then no water would be needed.

Thus, while the amount of water demand that would be needed to operate NOx control equipment would be 398,767 gallons per day at Refineries 1, 5 and 6 and the amount of water demand at Refineries 2, 4, 8, and 9 would be in the range of 113,836 gallons per day to 160,211 gallons per day, which collectively is greater than the significance threshold of 262,820 gallons per day of potable water but less than the significance threshold of five million gallons per day of total water (e.g., potable, recycled, and groundwater), in consideration that Refineries 1, 5 and 6 have a high potential to use recycled water because of their current access and in light of the negotiations for recycled water at Refineries 4, 8, and 9, potable water only may be needed for a future project occurring at Refinery 2, or not at all if operators of Refinery 2 choose to install a DGS instead of a WGS. In any case, the previous analysis shows that water purveyor would be able to supply potable water to Refinery 2 and to Refineries 1, 4, 5, 6, 8 and 9, if needed. Thus,

[5] City of Los Angeles, Inter-Departmental Correspondence to City Council From Los Angeles Department of Water and Power and Los Angeles Department of Public Works Bureau of Sanitation, Council File No. 15-0018 Harbor Refineries Pipeline Project/Advanced Water Purification Facility/Water Supply Efforts, April 10, 2015. https://cityclerk.lacity.org/lacityclerkconnect/index.cfm?fa=ccfi.viewrecord&cfnumber=15-0018

using an abundance of caution, because the peak daily water demand for the proposed project exceeds the potable water threshold of 262,820 gallons per day and because recycled water is not currently available at Refineries 4, 8 and 9, and no contractual commitments to increase recycled water demand above the existing recycled water baseline for the three refineries that already have access to recycled water (e.g., Refineries 1, 5 and 6) have been finalized, the analysis conservatively assumes that significant adverse impacts associated with water demand are expected from the proposed project during operation.

Thus, while the mitigation measures that are identified in the Mitigation Monitoring Plan section of this document may reduce potable water demand associated with operation activities to the maximum extent feasible, the overall effectiveness of the mitigation measures is dependent upon whether each facility has access to recycled water. While feasible mitigation measures have been identified to reduce the potable water demand, the potable water demand may not necessarily be reduced to a level of insignificance because of limitations with access to recycled water. Thus, the proposed mitigation measures may not fully avoid the significant impact or reduce the potable water demand impact to less than significant. Also, no other feasible mitigation measures have been identified to reduce the operational potable water demand to a level of insignificance. Therefore, the proposed project is considered to have significant adverse unavoidable cumulative water demand impacts during operation.

<u>Hazards and Hazardous Materials Impacts From Delivering Ammonia</u>

The Final PEA assumes that some facilities may opt to reduce NOx emissions by installing NOx control equipment such as SCRs and DGSs which requires the use of ammonia, a chronic and acutely hazardous material. Further, an increase in the use of ammonia in response to the proposed project may increase the current existing risk setting associated with deliveries (i.e., truck and road accidents). In particular, the analysis assumes that as many as 117 SCRs could be installed at 20 facilities and one Ultracat DGS could be installed at one facility. The analysis estimates that approximately 39.5 tons per day (equivalent to approximately 10,284 gallons per day) of aqueous ammonia (at 19 percent concentration) would be needed to operate the equipment. It is expected that the affected facilities will receive ammonia from a local ammonia supplier located in the greater Los Angeles area. Deliveries of aqueous ammonia would be made by tanker truck via public roads.

The accidental release of ammonia from a delivery is a localized event (i.e., the release of ammonia would only affect the receptors that are within the zone of the toxic endpoint). The accidental release from a delivery would also be temporally limited in the fact that deliveries are not likely to be made at the same time in the same area. Based on these limitations, the analysis in the Final PEA assumed that an accidental release would be limited to a single delivery or single facility at a time. In the ammonia transportation release scenario, the distance to the toxic endpoint from a worst-case delivery truck release was estimated to be 0.4 miles or 2,112 feet. Since sensitive receptors are expected to be found within 0.4 miles from roadways, the hazards and hazardous materials impacts due to a delivery truck accident were concluded to be potentially significant. Therefore, the proposed project was concluded to have significant adverse hazards and hazardous materials impacts due to ammonia deliveries and mitigation measures are required. However, no feasible mitigation measures have been identified, over and above the extensive safety regulations that currently apply to delivery trucks that haul ammonia.

FINDINGS

Public Resources Code §21081 and CEQA Guidelines §15091 (a) state that no public agency shall approve or carry out a project for which a CEQA document has been completed which identifies one or more significant adverse environmental effects of the project unless the public agency makes one or more written findings for each of those significant effects, accompanied by a brief explanation of the rationale for each finding. Additionally, the findings must be supported by substantial evidence in the record (CEQA Guidelines §15091 (b)). As identified in the Final PEA and summarized above, the proposed project has the potential to create significant adverse impacts for the topics of air quality during construction, water demand, and hazardous materials due to deliveries of ammonia. The SCAQMD Governing Board, therefore, makes the following findings regarding the proposed project. The findings are supported by substantial evidence in the record as explained in each finding. The findings will be included in the record of project approval and will also be noted in the Notice of Decision. The findings made by the SCAQMD Governing Board are based on the following significant adverse impacts identified in the Final PEA.

1. **Potential project-specific and cumulative VOC, CO, NOx, PM10, and PM2.5 emissions during construction exceed the SCAQMD's applicable significance air quality thresholds and cannot be mitigated to insignificance.**

   Finding and Explanation:
   The implementation of the proposed project is anticipated to trigger construction activities associated with the installation of new or the modification of existing NOx air pollution control equipment. Construction activities associated with the proposed project would result in emissions of VOC, CO NOx, SOx, PM10, and PM2.5, but only the estimated emissions for SOx are expected to remain below the SCAQMD's applicable significance air quality thresholds for construction. As a result, the proposed project is expected to have significant adverse construction air quality impacts. However, the temporary construction emissions would cease upon completion of the installation of new or modification of existing air pollution control equipment, as applicable. Once all the modified or new equipment are in place, the proposed project is expected to result in a reduction of NOx emissions of 14 tons per day by 2023.

   The Governing Board finds that mitigation measures have been identified, but they would not reduce to insignificance the significant adverse project-specific or cumulative impacts to air quality associated with construction. No other feasible mitigation measures have been identified. CEQA Guidelines §15364 defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors."

   The Governing Board further finds that the Final PEA considered alternatives pursuant to CEQA Guidelines §15126.6, but there is no alternative to the project, other than the No Project Alternative (Alternative 4), that would reduce to insignificant levels the significant project-specific or cumulative construction air quality impacts that were identified for the proposed project. However, the No Project Alternative (Alternative 4) was rejected due to infeasibility. Specifically Alternative 4 was determined to not be a legally viable alternative because it violates a state law requirement in Health and Safety Code §40440 that regulations mandate the use of BARCT for existing sources.

2. **Potential GHG emissions exceed the SCAQMD's applicable significance GHG threshold and cannot be mitigated to insignificance.**

   Finding and Explanation:
   While none of the affected facilities individually exceed the SCAQMD's industrial GHG significance threshold of 10,000 MTCO2e/yr, if the proposed project is implemented, the analysis indicates that there would be a significant increase in GHG emissions for the project as a whole. Because there are significant adverse GHG impacts from the proposed project, the PEA must describe feasible measures that could minimize significant adverse impacts.

   The Governing Board finds that mitigation measures have been identified, but they would not reduce to insignificance the significant adverse GHG emission impacts. No other feasible mitigation measures have been identified. CEQA Guidelines §15364 defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors."

   The Governing Board further finds that the Final PEA considered alternatives pursuant to CEQA Guidelines §15126.6, but there is no alternative to the project, other than the No Project Alternative (Alternative 4), that would reduce to insignificant levels the significant GHG impacts that were identified for the proposed project. However, the No Project Alternative (Alternative 4) was rejected due to infeasibility. Specifically Alternative 4 was determined to not be a legally viable alternative because it violates a state law requirement in Health and Safety Code §40440 that regulations mandate the use of BARCT for existing sources.

3. **Potential potable water demand would use a substantial amount of potable water and cannot be mitigated to insignificance.**

   Finding and Explanation:
   The Final PEA concluded that the proposed project may cause significant adverse potable water demand impacts during hydrotesting post-construction but prior to operation and during operation of NOx control equipment. Because there are significant adverse potable water demand impacts from the proposed project, the Final PEA must describe feasible measures that could minimize significant adverse impacts. Mitigation measures have been identified that may be effective in reducing the amount of potable water needed, however, they may not completely avoid or reduce the adverse potable water demand impact to a less than significant level.

   The Governing Board finds that mitigation measures have been identified, but they would not reduce to insignificance the significant adverse water demand impacts. No other feasible mitigation measures have been identified. CEQA Guidelines §15364 defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors."

The Governing Board further finds that the Final PEA considered alternatives pursuant to CEQA Guidelines §15126.6, but there is no alternative to the project, other than the No Project Alternative (Alternative 4), that would reduce to insignificant levels the significant water demand impacts that were identified for the proposed project. However, the No Project Alternative (Alternative 4) was rejected due to infeasibility. Specifically Alternative 4 was determined to not be a legally viable alternative because it violates a state law requirement in Health and Safety Code §40440 that regulations mandate the use of BARCT for existing sources.

4. **Potential hazards and hazardous materials impacts due to deliveries of ammonia may significantly increase the current existing risk setting associated with truck and road accidents and cannot be mitigated to insignificance.**

<u>Finding and Explanation</u>:
The Final PEA concluded that the proposed project may cause significant adverse hazards and hazardous materials impacts during deliveries of ammonia to facilities that may install NOx emissions control equipment that require the use of ammonia. Because there are significant adverse hazards and hazardous materials impacts from the proposed project, the Final PEA must describe feasible measures that could minimize significant adverse impacts. However, no feasible mitigation measures have been identified, over and above the extensive safety regulations that currently apply to delivery trucks that haul ammonia, that could minimize or reduce the significant hazards and hazardous materials impacts due to deliveries of ammonia.

The Governing Board finds that no feasible mitigation measures have been identified that would reduce to insignificance the significant adverse hazards and hazardous materials impacts due to deliveries of ammonia. CEQA Guidelines §15364 defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors."

The Governing Board further finds that the Final PEA considered alternatives pursuant to CEQA Guidelines §15126.6, but there is no alternative to the project, other than the No Project Alternative (Alternative 4), that would reduce to insignificant levels the significant hazards and hazardous materials impacts due to deliveries of ammonia that were identified for the proposed project. However, the No Project Alternative (Alternative 4) was rejected due to infeasibility. Specifically Alternative 4 was determined to not be a legally viable alternative because it violates a state law requirement in Health and Safety Code §40440 that regulations mandate the use of BARCT for existing sources.

Conclusion of Findings

The Governing Board finds that feasible mitigation measures have been identified to help minimize the potentially significant adverse impacts to the following topics: air quality during construction, GHG emissions, and water demand. The Governing Board also finds that no feasible mitigation measures have been identified to help minimize the potentially significant adverse impacts to hazards and hazardous materials due to deliveries of ammonia. CEQA defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors" (Public Resources Code §21061.1).

The Governing Board further finds that the Final PEA considered alternatives pursuant to CEQA Guidelines §15126.6, but there is no alternative to the project, other than the No Project Alternative (Alternative 4), that would reduce to insignificant levels the significant impacts to the topics of air quality during construction, GHG emissions, water demand, and hazards and hazardous materials due to deliveries of ammonia that were identified for the proposed project. However, the No Project Alternative (Alternative 4) was rejected due to infeasibility. Specifically Alternative 4 was determined to not be a legally viable alternative because it violates a state law requirement in Health and Safety Code §40440 that regulations mandate the use of BARCT for existing sources.

The Governing Board further finds that a Mitigation Monitoring Plan (pursuant to Public Resources Code §21081.6) needs to be prepared since feasible mitigation measures were identified for the topics of air quality during construction, GHG emissions, and water demand.

The Governing Board further finds that the findings required by CEQA Guidelines §15091 (a) are supported by substantial evidence in the record. Further, to comply with CEQA Guidelines §15091 (e), the SCAQMD specifies the director of Regulation XX as the custodian of the documents or other materials which constitute the record of proceedings upon which the adoption of these proposed amendments and the approval of this project is based, and which are located at the SCAQMD headquarters, 21865 Copley Drive, Diamond Bar, California 91765.

STATEMENT OF OVERRIDING CONSIDERATIONS

If significant adverse impacts of a proposed project remain after incorporating mitigation measures, or no measures or alternatives to mitigate the adverse impacts are identified, the lead agency must make a determination that the benefits of the project outweigh the unavoidable adverse environmental effects if it is to approve the project. CEQA requires the decision-making agency to balance, as applicable, the economic, legal, social, technological, or other benefits of a proposed project against its unavoidable environmental risks when determining whether to approve the project [CEQA Guidelines §15093 (a)]. If the specific economic, legal, social, technological, or other benefits of a proposed project outweigh the unavoidable adverse environmental effects, the adverse environmental effects may be considered “acceptable” [CEQA Guidelines §15093 (a)]. Accordingly, a Statement of Overriding Considerations regarding potentially significant adverse impacts to air quality during construction, GHGs, water demand, and hazardous materials due to deliveries of ammonia that may result from the proposed project has been prepared. This Statement of Overriding Considerations is included as part of the record of the project approval for the proposed project. Pursuant to CEQA Guidelines

§15093 (c), the Statement of Overriding Considerations will also be noted in the Notice of Decision for the proposed project.

Despite the inability to incorporate changes into the proposed project that will mitigate potentially significant adverse impacts to a level of insignificance for the topics of air quality during construction, GHG emissions, water demand, and, hazards and hazardous materials due to deliveries of ammonia, the SCAQMD's Governing Board finds that the following benefits and considerations outweigh the significant unavoidable adverse environmental impacts:

1. The analysis of potential adverse environmental impacts incorporates a "worst-case" approach. This entails the premise that whenever the analysis requires that assumptions be made, those assumptions that result in the greatest adverse impacts are typically chosen. This method likely overestimates the actual environmental impacts from the proposed project.

2. Each of the alternatives was crafted to show the various possibilities or permutations of how operators of NOx RECLAIM facilities could achieve actual NOx reductions, but ultimately, there is no way to predict what each facility operator will do. Further, because of the compliance flexibility inherent in the RECLAIM program, affected operators may choose to reduce NOx emissions using compliance options that minimize or eliminate significant environmental impacts at their facilities.

3. The 2012 AQMP identifies ambient air pollutant levels relative to federal and state ambient air quality standards (AAQS), establishes baseline and future emissions, and develops control measures to ensure attainment of the AAQS. Construction is a continuous activity in the district and is accounted for in the AQMP. Thus, any changes in air quality as a result of construction emissions from the proposed project are accounted for in the AQMP and would not be expected to interfere with the attainment demonstrations.

4. The proposed project implements 2012 AQMP Control Measure #CMB-01: Further NOx Reductions from RECLAIM (e.g., at least three to five tons per day by 2023). The proposed project will remove NOx RTCs by 14 tons per day by 2023. In addition, the proposed project is designed to implement both the Phase I and Phase II reduction commitments described in #CMB-01.

5. Although the proposed project also has the largest amount of adverse environmental impacts overall when compared to the alternatives, it achieves the maximum level of NOx reductions and corresponding health benefits.

6. Considering the need for expeditious improvement in air quality, the proposed project is preferred over the other alternatives considered because it provides the best balance between reducing NOx emissions relative to the adverse impacts.

7. Implementing the control measures in the 2012 AQMP will result in an overall net reduction in criteria pollutant emissions. Therefore, cumulative air quality impacts from the proposed project and all other AQMP control measures when considered together, are not expected to

be significant because implementation of all AQMP control measures is expected to result in net emission reductions and overall air quality improvement.

The SCAQMD's Governing Board finds that the above-described considerations outweigh the unavoidable significant effects to the environment as a result of the proposed project.

MITIGATION MONITORING PLAN

When making findings as required by Public Resources Code §21081 and CEQA Guidelines §15091, the lead agency must adopt a reporting or monitoring program for the changes to the project which it has adopted or made a condition of project approval in order to mitigate or avoid significant effects on the environment. [Public Resources Code §21081.6 and CEQA Guidelines §15097 (a)]. To fulfill the requirements of Public Resources Code §21081.6 and CEQA Guidelines §15097, the SCAQMD has developed this mitigation monitoring plan for anticipated impacts resulting from implementing the proposed project. Each operator of any facility required to comply with a mitigation monitoring plan shall keep records onsite of applicable compliance activities to demonstrate the steps taken to assure compliance with all of the mitigation measures, as applicable.

1. Air Quality Impacts During Construction

Impacts Summary: Project-specific and cumulative construction-related emissions of VOC, NOx, CO, PM10, and PM2.5 emissions, based on a "worst-case" analysis, would exceed the SCAQMD's regional mass daily significance thresholds for these pollutants. Emission sources include worker vehicles and heavy construction equipment. The following mitigation measures are intended to minimize the emissions associated with these sources during construction activities. No feasible mitigation measures have been identified to reduce emissions to a level of insignificance.

Mitigation Measures: The following construction mitigation measures are required for each of the affected facilities whose operators choose to install NOx control equipment. SCAQMD staff will conduct a CEQA evaluation of each facility-specific project proposed in response to the proposed project and determine if the project is covered by the analysis in this PEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing SCAQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by SCAQMD personnel.

On-Road Mobile Sources

AQ-1 Develop a Construction Emission Management Plan for each affected facility to minimize emissions from vehicles including, but not limited to: consolidating truck deliveries; scheduling deliveries to avoid peak hour traffic conditions; describing truck routing; describing deliveries including logging delivery times; describing entry/exit points; identifying locations of parking; identifying construction schedule; and prohibiting truck idling in excess of five consecutive minutes or another time-frame as allowed by the California Code of Regulations, Title 13 §2485 - CARB's Airborne Toxic Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling. The Construction Emission Management Plan shall be submitted to SCAQMD CEQA for approval prior to the start of construction. At a minimum the Construction Emission Management Plan would include the following types of mitigation measures.

Off-Road Mobile Sources:

AQ-2 Maintain construction equipment tuned to manufacturer's recommended specifications that optimize emissions without nullifying engine warranties.

AQ-3 The project proponent shall survey and document the proposed project's construction areas and identify all construction areas that are served by electricity. This documentation shall be provided as part of the Construction Emissions Management Plan.

AQ-4 For all construction areas that are demonstrated to be served by electricity, use electricity for on-site mobile equipment instead of diesel equipment to the extent feasible. For example, electric welders should be used in lieu of diesel or gasoline-fueled welders and onsite electricity should be used in lieu of temporary power generators. If electricity is not available, use alternative fuels where feasible.

AQ-5 All off-road diesel-powered construction equipment greater than 50 hp shall meet Tier-4 off-road emission standards at a minimum. In addition, if not already supplied with a factory-equipped diesel particulate filter, all construction equipment shall be outfitted with Best Available Control Technology (BACT) devices certified by CARB. Any emissions control device used by the contractor shall achieve emissions reductions that are no less than what could be achieved by a Level 3 diesel emissions control strategy for a similarly sized engine as defined by CARB regulations. Construction equipment shall incorporate, where feasible, emissions-reducing technology such as hybrid drives and specific fuel economy standards. In the event that any equipment required under this mitigation measure is not available, the project proponent shall provide documentation in the Construction Emissions Management Plan or associated subsequent status reports as information becomes available.

AQ-6 Suspend use of all construction activities that generate air pollutant emissions during first stage smog alerts as defined in SCAQMD Rule 701.

If, at the time when each facility-specific project is proposed in response to the proposed project, that improved emission reduction technologies become available for on- and off-road construction equipment, as part of the CEQA evaluation for the facility-specific project, the construction mitigation measures will be updated accordingly.

Implementing Parties: The SCAQMD's Governing Board finds that implementing the mitigation measures AQ-1 through AQ-6 is the responsibility of the owner, operator, or agent of each affected facility who submits a permit application to comply with the proposed project.

Monitoring Agency: The SCAQMD's Governing Board finds that through its discretionary authority to issue and enforce permits for this project, the SCAQMD will ensure compliance with mitigation measures AQ-1 through AQ-6. Mitigation monitoring and reporting (MMR) will be accomplished as follows:

MMRAQ-1: Construction Emission Management Plan
Each facility operator shall develop and submit a Construction Emission Management Plan to the SCAQMD for approval prior to starting construction activities. Upon approval, each facility operator shall train all personnel subject to the requirements set forth in the Construction Emission Management Plan on how to comply with the requirements in the plan, and document that training. The SCAQMD may conduct routine inspections of the site to verify compliance. The Construction Emission Management Plan shall include, at a minimum, the following information:

- A construction schedule of activities for each construction phase that indicates the number of construction workers needed, and the type, fuel source, and number of construction equipment needed for each construction phase;
- A description of truck routing with a priority given to consolidating truck deliveries and scheduling deliveries to avoid peak hour traffic conditions;
- A format or system for logging delivery dates, times, and type of deliveries;
- A description of entry/exit points to the construction site;
- An identification of parking locations at the construction site; and,
- A description of how the prohibition of truck idling in excess of five consecutive minutes or another time-frame as allowed by the CCR Title 13 §2485, will be conveyed to truck drivers.

Traffic Control
Traffic requiring entrance onto each facility's property will be directed toward the entry gate or gates, if there are multiple entrances, so that congestion, as well as associated air pollution, will be minimized.

Points of entry will be selected to maximize facility security and reduce traffic-associated emissions. Each facility operator will direct their Receiving Department to consider delivery items, time of delivery, in-plant congested areas, surrounding area traffic, and gate security issues when assigning a gate entry location.

On-site parking will be used to the maximum extent available. In the event that off-site parking is required, construction workers may be requested to park at a designated off-site property. Buses or some other type of shuttle may transfer multiple workers at one time to and from the project site. No on-street parking (i.e., off of each facility's site) will be allowed.

Each facility operator will limit the number of personal and company vehicles allowed to enter each facility beyond the parking lots. This restriction helps minimize onsite emissions and promotes the use of ride sharing and alternate fueled transportation such as bicycles and electric golf carts.

Construction Schedule
In an effort to reduce traffic by construction workers, operators of the each facility may request its contractors to follow a compressed workweek. An example of a compressed workweek would be a four-day work week and a 10-hour work day with most work scheduled to begin by 7:00 a.m. and end after 5:30 p.m., Monday through Friday, to further minimize traffic congestion and related emissions. In addition, some work may need to be scheduled during the night shift, which will begin after 6:00 p.m. and end around 4:30 a.m. Critical path work may require a deviation from the aforementioned workweek and start- and stop-times; however, deviations will be minimized.

During process unit shutdowns, extended work shifts and night shifts, scheduled six to seven days per week, may be necessary. Each facility operator will establish in their Construction Emission Management Plan the details of the construction schedule, including operating hours, days, and number of shifts per day. This construction work schedule will need to be designed to minimize the travel time during peak travel periods.

Trip Reduction Plan
No feasible mitigation has been identified for the emissions from on-road vehicle trips. CEQA Guidelines §15364 defines feasible as "...capable of being accomplished in a successful manner." No feasible mitigation measures for offsite motor vehicles have been identified. Health and Safety Code §40929

prohibits the air districts and other public agencies from requiring an employee trip reduction program making such mitigation infeasible.

Delivery of Equipment and Materials
Each facility operator will coordinate the delivery of equipment and materials to avoid peak hour traffic, whenever possible. That is, delivery of construction materials to the site will be scheduled to occur during off-peak periods which are typically from 8:30 a.m. until 4:00 p.m. Monday through Friday. Each facility operator will request that equipment and material deliveries be minimized between the hours of 7:00 a.m. to 8:00 a.m. and 4:30 p.m. to 5:30 p.m. to reduce traffic in and out of each facility during high traffic peak times. Exceptions will be made for trucks carrying time-critical materials, e.g., concrete delivery and soil hauling (which eliminates the double handling or on-site stock-piling of soil, preventing it from being moved from place-to-place due to lack of adequate staging area, and subsequent removal at a later time via trucks). Delivery routes and schedules will be developed pursuant to the California Department of Transportation regulations.

It may be necessary to handle a limited amount of equipment as wide or special loads. These deliveries are subject to California Department of Transportation regulations and will be coordinated with local police departments. These trips will be scheduled to avoid peak hour traffic.

Prohibit Trucks From Idling Longer Than Five Minutes
Each facility operator will notify all vendors that during deliveries, truck idling time will be limited to no longer than five minutes or another time-frame as allowed by the California Code of Regulations, Title 13 §2485 - CARB's Airborne Toxic Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling. For any delivery that is expected to take longer than five minutes, each facility operator will require the truck's operator to shut off the engine. Each facility operator will notify the vendors of these delivery requirements at the time that the purchase order is issued and again when trucks enter the gates of the facility. To further ensure that drivers understand the truck idling requirement, signs will be posted at each facility entry gates stating idling longer than five minutes is not permitted.

MMRAQ-2: Maintain Construction Equipment, Tuned Up to Manufacturer's Recommended Specifications That Optimize Emissions Without Nullifying Engine Warranties

Each facility operator, in cooperation with the construction contractors, will maintain vehicle and equipment maintenance records for the construction portion of the proposed project. All construction vehicles must be maintained in compliance with the manufacturer's recommended maintenance schedule. Each facility operator will maintain their construction equipment and the construction contractor will be responsible for maintaining their equipment and maintenance records. All maintenance records for each facility and their construction contractor(s) will remain on-site for a period of at least two years from completion of construction.

MMRAQ-3: Survey of Construction Areas Where Electricity is Available for Operating Electric On-Site Mobile Equipment

Each facility operator and/or their construction contractor(s) will conduct a survey of the proposed project construction area(s) to assess whether the existing infrastructure can provide access to electricity, as available, within the facility or construction site, in order to operate electric on-site mobile equipment. For example, each facility operator and/or their construction contractor(s) will assess the number of electrical welding receptacles available.

Construction areas within the facility or construction site where electricity is and is not available must be clearly identified on a site plan as part of the Construction Emission Management Plan. The use of non-electric onsite mobile equipment shall be prohibited in areas of the facility that are shown to have access to electricity. The use of electric on-site mobile equipment within these identified areas of the facility or construction site will be allowed.

Each facility operator shall include in all construction contracts the requirement that the use of non-electric on-site mobile equipment is prohibited in certain portions of the facility as identified on the site plan. Each facility operator shall maintain records that indicate the location within the facility or construction site where all electric and non-electric on-site mobile equipment are operated, if at all, for a period of at least two years from completion of construction.

MMRAQ-4: Use Electricity or Alternate Fuels for On-Site Mobile Equipment Instead of Diesel Equipment to the Extent Feasible

Each facility operator and/or their construction contractor(s) shall evaluate the use of electricity and alternate fuels for on-site mobile construction equipment prior to the commencement of construction activities, provided that suitable equipment is available for the activity. Equipment vendors will be contacted to determine the commercial availability of electric or alternate-fueled construction equipment. Priority should be given to the use of electric on-site mobile construction equipment. If electricity is not available, then use alternative fuels to power on-site mobile construction equipment where feasible. Equipment that will use electricity or alternate fuels will be included in the Construction Emission Management Plan.

The potential equipment that may be considered includes, but is not limited to:

- Electric welders
- Electric scissor lifts
- Electric golf carts
- Bicycles
- Electric or bi-powered boom lifts

MMRAQ-5: All Off-Road Diesel-Powered Construction Equipment Greater Than 50 hp Shall Meet Tier 4 Off-Road Emission Standards and Shall Be Equipped With CARB-Certified Best Available Control Technology (BACT) Emissions Control Devices

Each facility operator shall include in all construction contracts the requirement that all off-road diesel-powered construction equipment greater than 50 hp shall meet Tier-4 off-road emission standards at a minimum. In addition, if not already supplied with a factory-equipped diesel particulate filter, all construction equipment shall be outfitted with Best Available Control Technology (BACT) devices certified by CARB. Any emissions control device used by the contractor shall achieve emissions reductions that are no less than what could be achieved by a Level 3 diesel emissions control strategy for a similarly sized engine as defined by CARB regulations. In addition, construction equipment shall incorporate, where feasible, emissions savings technology such as hybrid drives and specific fuel economy standards. In the event that any equipment required under this mitigation measure is not available, the project proponent shall provide documentation in the Construction Emissions Management Plan or associated subsequent status reports as information becomes available.

MMRAQ-6: Suspend All Construction Activities That Generate Air Emissions During First Stage Smog Alerts

If and when any first stage smog alert or greater occurs, each facility operator will record the date and time of each alert, will suspend all construction activities that generate emissions, and will record the date and time when the use of construction equipment and construction activities are suspended. This log shall be maintained on-site for a period of at least two years from completion of construction.

2. <u>GHG Impacts</u>

Impact Summary: Based on a "worst-case" analysis, none of the affected facilities individually exceed the industrial GHG significance threshold. However, if the proposed project gets implemented, the analysis indicates that there will be a significant increase in GHG emissions for the project as a whole. Because there are significant adverse GHG impacts from the proposed project, the PEA must describe feasible measures which could minimize the significant adverse impacts. The following mitigation measures are intended to minimize the GHG emissions associated with water conveyance. No feasible mitigation measures have been identified to reduce GHG emissions to a level of insignificance.

Mitigation Measures: The following mitigation measures will apply to any facility whose operator chooses to install NOx control equipment that utilizes water for its operation. SCAQMD staff will conduct a CEQA evaluation of each facility-specific project proposed in response to the proposed project and determine if the project is covered by the analysis in this PEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing SCAQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by SCAQMD personnel.

GHG-1: When NOx control equipment is installed and water is required for its operation, the facility operator is required to use recycled water, if available, to satisfy the water demand for the NOx control equipment.

GHG-2: In the event that recycled water cannot be delivered to the affected facility, the facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be supplied to the project.

Implementing Parties: The SCAQMD's Governing Board finds that implementing mitigation measures GHG-1 through GHG-2 is the responsibility of the owner, operator, or agent of each affected facility who submits a permit application to comply with the proposed project.

Monitoring Agency: The SCAQMD's Governing Board finds that through its discretionary authority to issue and enforce permits for this project, the SCAQMD will ensure compliance with mitigation measures GHG-1 through GHG-2. Mitigation monitoring and reporting (MMR) will be accomplished as follows:

MMRGHG-1: Use Recycled Water, If Available, for NOx Control Equipment That Requires Water for Its Operation
At the time of submitting an application for a Permit to Construct for NOx control equipment and water is required for its operation, each facility operator shall submit a copy of a Memorandum of Understanding agreement reached between the facility operator and the recycled water supplier or purveyor that indicates recycled water will be used to supply water to the NOx control equipment. Once the NOx control equipment becomes operational, on a monthly basis, each facility operator will record the amount of recycled water delivered to the NOx control equipment from the recycled water bill. This log shall be maintained on-site for a period of at least two years from initiating operation.

MMRGHG-2: Submit Written Declaration if Recycled Water is Not Available
The facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project.

3. <u>Water Demand Impacts</u>

Impacts Summary - Hydrotesting: Some NOx control equipment may also require the installation of support equipment such as storage tanks, for example, which need to undergo hydrotesting in order to verify the structural integrity prior to operation. Because hydrotesting can utilize a substantial amount of water, significant adverse impacts associated with water demand during hydrotesting are expected from the proposed project post-construction but prior to operation. For example, for any facility that installs NOx control equipment that also requires the installation of support equipment, such as a storage tank or other equipment, to be installed and hydrotested as part of the proposed project, the use of non-potable water such as recycled water or diverted process water can help substantially reduce the water demand impacts to a less than significant level if facility operators that have access to recycled water or diverted non-potable process water are required to use recycled water or diverted non-potable process water.

The water demand analysis during hydrotesting shows that the potential increase in potable water use cannot be fully supplied entirely with recycled water because recycled water is not currently delivered to all of the affected facilities. While there are ongoing negotiations to connect some of the affected facilities to recycled water at a future date, there are currently no contractual commitments in place to bring recycled water to these facilities. Further, for the facilities that currently have access to recycled water, there are currently no contractual commitments in place with the recycled water purveyors to provide an increased amount of recycled water deliveries above the existing baseline, even though there is plenty of recycled water supply available, to accommodate the increased demand for hydrotesting water that may result from the proposed project. Also, the potential increase in potable water use for hydrotesting cannot be fully supplied entirely by other non-potable water such as diverted process water because not all of the facilities have on-site sources of process water that can be diverted for hydrotesting purposes. Thus, some potable water may still be required to conduct hydrotesting.

In conclusion, because potable water may still be needed in the event that recycled water or other non-potable process water may not be available to all of the affected facilities, the analysis conservatively assumes that the water demand impacts during hydrotesting could remain significant after mitigation.

Because there are significant adverse water demand impacts from the proposed project post-construction but prior to operation during hydrotesting of support equipment, the PEA must describe feasible measures which could minimize the significant adverse impacts for hydrotesting activities. The following mitigation measures are intended to minimize the amount of potable water used for hydrotesting by requiring either recycled water or other non-potable water as a substitute, but the overall effectiveness of the mitigation measures is dependent upon whether each facility has access to these alternate water sources. While the following feasible mitigation measures have been identified to reduce the potable water demand, the potable water demand may not necessarily be reduced to a level of insignificance because of the aforementioned limitations with access to either recycled water or other non-potable water.

Mitigation Measures for Hydrotesting: The following water demand mitigation measures are required during hydrotesting for any facility that installs NOx control equipment with support equipment that requires hydrotesting prior to its operation as part of the proposed project. SCAQMD staff will conduct a CEQA evaluation of each facility-specific project proposed in response to the proposed project and determine if the project is covered by the analysis in this PEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing SCAQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by SCAQMD personnel.

HWQ-1 When support equipment such as a storage tank is installed to support operations of installed NOx control equipment and hydrotesting is required prior to operation, the facility operator is required to use, in lieu of potable water, recycled water or other non-potable process water temporarily diverted from elsewhere within the facility, if available, to satisfy the water demand for hydrotesting.

HWQ-2 For hydrotesting purposes, in the event that recycled water cannot be delivered to the affected facility and diverted non-potable process water is not used, the facility operator is required to submit two written declarations with the application for a Permit to Construct for the NOx control equipment and any support equipment such as a storage tank or other equipment that requires hydrotesting, one to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project and one from a high-ranking officer at the facility indicating the reason(s) and the supporting evidence that explains why the non-potable process water cannot be diverted to the project from elsewhere within the facility.

Impacts Summary – Operation of Air Pollution Control Equipment: Of the technologies proposed as BARCT for NOx control, only wet gas scrubber (WGS) technology utilizes water as part of their day-to-day operations and the amount of water needed on a daily basis is substantial and exceeds the significance threshold for potable water. Thus, significant adverse impacts associated with water demand during operation of WGSs are also expected from the proposed project. However, for any facility that installs NOx control equipment that also requires water for its operation, the use of recycled water can help substantially reduce the water demand impacts to a less than significant level if facility operators that have access to recycled water are required to use recycled water instead of potable water. SCAQMD staff has verified that the water supply projections made by the water purveyors that provide water to the affected sources will be able to supply either potable water or recycled water, as applicable, to satisfy the potential water demand needs of the proposed project. However, the water demand analysis during operation shows that the potential increase in potable water use cannot be fully replaced with all recycled water because recycled water is not currently delivered to all of the affected facilities. While there are ongoing negotiations to connect some of the affected facilities to recycled water at a future date, there are currently no contractual commitments in place to bring recycled water to these facilities. Further, for the facilities that currently have access to recycled water, there are currently no contractual commitments in place with the recycled water purveyors to provide an increased amount of recycled water deliveries above the existing baseline. Thus, some potable water may still be required to operate air pollution control equipment.

In conclusion, because potable water may still be needed in the event that recycled water may not be available to all of the affected facilities, the analysis conservatively assumes that the water demand impacts during operation could remain significant after mitigation.

Because there are significant adverse water demand impacts from the proposed project during operation, the PEA must describe feasible measures which could minimize the significant adverse water demand impacts during operation. The following mitigation measures are intended to minimize the amount of potable water used for operating air pollution control equipment by requiring recycled water, but the overall effectiveness of the mitigation measures is dependent upon whether each facility has access to recycled water, even if plenty of recycled water is available. While the following feasible mitigation measures have been identified to reduce the potable water demand, the potable water demand may not necessarily be reduced to a level of insignificance because of the aforementioned limitations with access to recycled water.

Mitigation Measures for Operations of NOx Control Equipment That Utilizes Water: The following water demand mitigation measures are required during operation of any WGS or any other type of NOx control equipment that utilizes water for its operation that is installed as part of the proposed project.

HWQ-3 When NOx control equipment is installed and water is required for its operation, the facility operator is required to use recycled water, if available, to satisfy the water demand for the NOx control equipment.

HWQ-4 In the event that recycled water cannot be delivered to the affected facility, the facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project.

Implementing Parties: The SCAQMD's Governing Board finds that implementing the mitigation measures HWQ-1 through HWQ-4 is the responsibility of the owner, operator, or agent of each affected facility who submits a permit application to comply with the proposed project.

Monitoring Agency: The SCAQMD's Governing Board finds that through its discretionary authority to issue and enforce permits for this project, the SCAQMD will ensure compliance with mitigation measures HWQ-1 through HWQ-4. Mitigation monitoring and reporting (MMR) will be accomplished as follows:

MMRHWQ-1: USE RECYCLED WATER OR OTHER NON-POTABLE PROCESS WATER, IF AVAILABLE, FOR HYDROTESTING

At the time of submitting an application for a Permit to Construct for NOx control equipment and any support equipment such as storage tank or other equipment that requires hydrotesting, each facility operator shall submit one of the following: 1) a copy of a Memorandum of Understanding agreement reached between the facility operator and the recycled water supplier or purveyor that indicates recycled water will be used to supply water to conduct hydrotesting; or, 2) a supplement to the application(s) that describes how other non-potable process water will be diverted for hydrotesting. Once hydrotesting is complete, each facility operator will record one of the following: 1) the amount of recycled water delivered for hydrotesting from the recycled water bill; or 2) the amount of diverted process water used for hydrotesting. This log shall be maintained on-site for a period of at least two years from conducting hydrotesting.

MMRHWQ-2: SUBMIT WRITTEN DECLARATION IF RECYCLED WATER AND OTHER NON-POTABLE PROCESS WATER IS NOT USED FOR HYDROTESTING

The facility operator is required to submit two written declarations with the application for a Permit to Construct for the NOx control equipment and any support equipment such as a storage tank or other equipment that requires hydrotesting, one to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project and one from a high-ranking officer at the facility indicating the reason(s) and the supporting evidence that explains why the non-potable process water cannot be diverted to the project from elsewhere within the facility.

MMRHWQ-3: USE RECYCLED WATER, IF AVAILABLE, FOR NOX CONTROL EQUIPMENT THAT REQUIRES WATER FOR ITS OPERATION

At the time of submitting an application for a Permit to Construct for NOx control equipment that requires water for its operation, each facility operator shall submit a copy of a Memorandum of Understanding agreement reached between the facility operator and the recycled water supplier or purveyor that indicates recycled water will be used to supply water to the NOx control equipment. Once the NOx control equipment becomes operational, on a monthly basis, each facility operator will record the amount of recycled water delivered to the NOx control equipment from the recycled water bill. This log shall be maintained on-site for a period of at least two years from initiating operation.

MMRHWQ-4: SUBMIT WRITTEN DECLARATION IF RECYCLED WATER IS NOT AVAILABLE FOR NOX CONTROL EQUIPMENT THAT REQUIRES WATER FOR ITS OPERATION

The facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project.

CONCLUSION

Based on a "worst-case" analysis, the potential adverse construction air quality impacts, GHG impacts, water demand impacts, and hazards and hazardous materials impacts due to deliveries of ammonia from the adoption and implementation of the proposed project are considered significant and unavoidable. Feasible mitigation measures have been identified for construction air quality impacts, GHG impacts, and water demand impacts that would reduce these impacts associated with the proposed project; however, the mitigation measures are not sufficient to reduce the impacts to insignificance. No feasible mitigation measures have been identified to help minimize the potentially significant adverse impacts to hazards and hazardous materials due to deliveries of ammonia.

Further, none of the alternatives analyzed would reduce the construction air quality impacts, GHG impacts, water demand impacts, and hazards and hazardous materials impacts due to deliveries of ammonia to less than significant. As a result, no other feasible mitigation measures or project alternatives have been identified that would further reduce these impacts while still achieving the overall objectives of the proposed project.

(PR 1109.1 November 5, 2021)

[*RULE INDEX TO BE ADDED AFTER RULE ADOPTION*]

PROPOSED RULE 1109.1. EMISSIONS OF OXIDES OF NITROGEN FROM PETROLEUM REFINERIES AND RELATED OPERATIONS

(a) Purpose

The purpose of this rule is to reduce emissions of Oxides of Nitrogen (NOx), while not increasing carbon monoxide (CO) emissions, from Units at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries.

(b) Applicability

The provisions of this rule shall apply to owners or operators of Facilities with Units at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries.

(c) Definitions

(1) ALTERNATIVE BARCT NOx LIMIT means a Unit specific NOx concentration limit that is selected by an owner or operator of a Facility for a B-Plan or B-Cap for Phase I, Phase II, or if applicable, Phase III of an I-Plan in Table 6 – I-Plan Percent Reduction Targets of Required Reductions and Compliance Schedule (Table 6). An Alternative BARCT NOx Limit is a concentration limit that meets the Best Available Retrofit Control Technology (BARCT) requirements in the aggregate.

(2) ASPHALT PLANT means a Facility that processes crude oil into asphalt.

(3) BARCT B-CAP ANNUAL EMISSIONS means the sum of the mass emissions from the Unit B-Cap Annual Emissions for each phase of an I-Plan, that is based on the Alternative BARCT NOx Limits, decommissioned Units, and other emission reduction strategies to meet the respective Phase I, Phase II, or if applicable, Phase III Facility BARCT Emission Targets in an I-Plan as calculated pursuant to Attachment B of this rule.

(4) BARCT EQUIVALENT COMPLIANCE PLAN (B-PLAN) means a compliance plan that allows an owner or operator of a Facility to select Alternative BARCT NOx Limits for all Units subject to the B-Plan that will achieve emission reductions that are greater in the aggregate than the mass emission reductions that would be achieved based on the NOx

Concentration Limits in Table 1 – NOx and CO Concentration Limits (Table 1) or Table 2 – Conditional NOx and CO Concentration Limits (Table 2).

(5) BARCT EQUIVALENT MASS CAP PLAN (B-CAP) means a compliance plan that establishes a Facility mass emission cap for all units subject to the B-Cap that, in the aggregate, is less than the Final Phase Facility BARCT Emission Target.

(6) BARCT EQUIVALENT MASS EMISSIONS means the total Facility NOx mass emissions remaining in Phase I, Phase II, or if applicable, Phase III of an I-Plan option in Table 6 based on the Alternative BARCT NOx Limits, as calculated pursuant to Attachment B of this rule.

(7) BASELINE FACILITY EMISSIONS means the sum of all the Baseline Unit Emissions at a Facility, as calculated pursuant to Attachment B of this rule.

(8) BASELINE UNIT EMISSIONS means emissions from a Unit as reported in the 2017 NOx Annual Emissions Report, or another representative year, as approved by the Executive Officer and included in "Baseline NOx Emissions and Representative NOx Concentrations for Facilities Regulated Under Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations" pursuant to paragraph (h)(3).

(9) BIOFUEL PLANT means a Facility that produces fuel by processing feedstocks including vegetable oil, animal fats, and tallow.

(10) BOILER means any Unit that is fired with gaseous fuel and used to produce steam. For the purpose of this rule, boiler does not include CO Boilers.

(11) CO BOILER means a Unit that is fired with gaseous fuel with an integral waste heat recovery system used to oxidize CO-rich waste gases generated by the FCCU.

(12) CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) is as defined by Rule 218.2 – Continuous Emission Monitoring System: General Provisions.

(13) CORRESPONDING CO CONCENTRATION LIMIT(S) means the CO concentration limit, that corresponds to the referenced NOx concentration limit, at the applicable percent oxygen (O_2) correction and averaging period specified in Table 1, Table 2, or Table 3 – Interim NOx and CO Concentration Limits (Table 3).

(14) DUCT BURNER means a device in the heat recovery steam generator of a Gas Turbine that combusts fuel and adds heat energy to the Gas Turbine exhaust.

(15) FACILITIES WITH RELATED OPERATIONS TO PETROLEUM REFINERIES include Asphalt Plants, Biofuel Plants, Hydrogen Production Plants, Petroleum Coke Calcining Facilities, Sulfuric Acid Plants, and Sulfur Recovery Plants.

(16) FACILITIES WITH THE SAME OWNERSHIP means Facilities and their subsidiaries, Facilities that share the same board of directors, or Facilities that share the same parent corporation.

(17) FACILITY means, for the purpose of this rule, any Unit or group of Units which are located on one or more contiguous properties, in actual physical contact or separated solely by a public roadway or other public right-of-way, and operate under one South Coast AQMD Facility ID or Facilities With The Same Ownership.

(18) FACILITY BARCT EMISSION TARGET means the total remaining NOx mass emissions that are based on the Percent Reduction Targets in each phase of a Table 6 I-Plan that are applied to the overall NOx emission reductions for the Units included in an approved B-Plan or B-Cap, as calculated pursuant to Attachment B of this rule.

(19) FINAL DETERMINATION NOTIFICATION means the notification issued by the Executive Officer to a Facility participating in the NOx Regional Clean Air Incentives Market (RECLAIM) program, designating that the Facility is no longer in the NOx RECLAIM program.

(20) FINAL PHASE FACILITY BARCT EMISSION TARGET means the total remaining NOx mass emissions that incorporates the NOx concentration limits in paragraph (h)(4) for all Units included in an I-Plan, B-Plan or B-Cap, calculated pursuant to Attachment B of this rule.

(21) FLARE means, for the purpose of this rule, a combustion device that oxidizes combustible gases or vapors from tank farms or liquid unloading, where the combustible gases or vapors being destroyed are routed directly into the burner without energy recovery, and that is not subject to Rule 1118 – Control of Emissions from Refinery Flares.

(22) FLUIDIZED CATALYTIC CRACKING UNIT (FCCU) means a Unit in which petroleum intermediate feedstock is charged and fractured into smaller molecules in the presence of a catalyst; or reacts with a contact

material to improve feedstock quality for additional processing; and the catalyst or contact material is regenerated by burning off coke and other deposits. The FCCU includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat including a CO Boiler.

(23) FORMER RECLAIM FACILITY means a Facility, including its successors, that was in the NOx Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX, that has received a Final Determination Notification, and is no longer in the NOx RECLAIM program.

(24) FUNCTIONALLY SIMILAR means, for the purpose of this rule, a Unit that will perform the same function and purpose as a Unit that was decommissioned in an approved B-Cap, including when the Unit that is decommissioned may be a different equipment category than the New Unit.

(25) GAS TURBINE means an internal-combustion engine in which the expanding combustion gases drive a turbine which then drives a generator to produce electricity. Gas Turbines can be equipped with a cogeneration Gas Turbine that recovers heat from the Gas Turbine exhaust and can include a Duct Burner.

(26) HEAT INPUT means the heat of combustion released by burning a fuel source, using the Higher Heating Value of the fuel. This does not include the enthalpy of incoming combustion air.

(27) HIGHER HEATING VALUE (HHV) means the total heat liberated per mass of fuel combusted expressed as British thermal units (Btu) per pound or cubic feet when fuel and dry air at Standard Conditions undergo complete combustion and all resulting products are brought to their standard states at Standard Conditions.

(28) HYDROGEN PRODUCTION PLANT means a Facility that produces hydrogen by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes which primarily supplies hydrogen for Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries.

(29) IMPLEMENTATION COMPLIANCE PLAN (I-PLAN) means an alternative implementation plan for an owner or operator of a Facility with six or more Units subject to this rule that includes an implementation schedule and emission reduction targets.

(30) I-PLAN PERCENT REDUCTION TARGET means the percent reduction target for each phase of an I-Plan, as specified in Table 6.

(31) NATURAL GAS means a mixture of gaseous hydrocarbons, with at least 80 percent methane (by volume), and of pipeline quality, such as the gas sold or distributed by any utility company regulated by the California Public Utilities Commission.

(32) NEW UNIT means, for the purpose of this rule, any Unit that is subject to this rule that meets the applicability of subdivision (b) where the South Coast AQMD Permit to Construct (Permit to Construct) is issued on or after [*DATE OF ADOPTION*].

(33) NOx AND CORRESPONDING CO CONCENTRATION LIMITS means an emission limit that includes the NOx Concentration Limit and the Corresponding CO Concentration Limit.

(34) NOx CONCENTRATION LIMIT(S) means the NOx concentration limit at the applicable percent O_2 correction and averaging period specified in Table 1, Table 2, Table 3, or Table 5 – Maximum Alternative BARCT NOx Concentration Limits for a B-Cap (Table 5).

(35) OPTIONAL UNITS means any Boiler or Process Heater with a Rated Heat Input Capacity of less than 40 MMBtu/hour that will meet the NOx concentration limits pursuant to subparagraph (d)(2)(B) or (d)(2)(C).

(36) OXIDES OF NITROGEN (NOx) EMISSIONS means the sum of nitric oxide and nitrogen dioxide emitted in the flue gas, calculated, and expressed as nitrogen dioxide.

(37) PARTS PER MILLION BY VOLUME (ppmv) means, for the purpose of this rule, Parts Per Million By Volume of a pollutant corrected to a dry basis at Standard Conditions.

(38) PETROLEUM COKE CALCINER means a Unit used to drive off contaminants from green petroleum coke by bringing the coke into contact with heated gas for the purpose of thermal processing. The Petroleum Coke Calciner includes, but is not limited to, a kiln, which is a refractory lined cylindrical device that rotates on its own axis, and a pyroscrubber, which combusts large carbon particles in a stream of waste gas.

(39) PETROLEUM COKE CALCINING FACILITY means a Unit within a Petroleum Refinery, or a separate Facility, that operates a Petroleum Coke Calciner.

(40) PETROLEUM REFINERY is a Facility that processes petroleum, as defined in the North American Industry Classification System Code as 324110 – Petroleum Refineries.

(41) PROCESS HEATER means any Unit fired with gaseous and/or liquid fuels which transfers heat from combusted gases to water or process streams.

(42) RATED HEAT INPUT CAPACITY means the maximum Heat Input capacity, which is the total heat of combustion released by burning a fuel source, as specified by the South Coast AQMD permit.

(43) REPRESENTATIVE NOx CONCENTRATION means the most representative NOx emissions in the exhaust of a Unit as included in "Baseline NOx Emissions and Representative NOx Concentrations for Facilities Regulated Under Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations" pursuant to paragraph (h)(3).

(44) STANDARD CONDITIONS for a Former RECLAIM Facility is as defined by Rule 102 – Definition of Terms.

(45) STEAM METHANE REFORMER (SMR) HEATER means any Unit that is fired with gaseous fuels and transfers heat from the combusted fuel to process tubes that contain catalyst, which converts light hydrocarbons combined with steam to hydrogen.

(46) SULFURIC ACID FURNACE means a Unit fueled with gaseous fuels and/or hydrogen sulfide gas used to convert elemental sulfur and/or decompose spent sulfuric acid into sulfur dioxide (SO_2) gas.

(47) SULFURIC ACID PLANT means Units within a Petroleum Refinery, or a separate Facility, engaged in the production of commercial grades of sulfuric acid, or regeneration of spent sulfuric acid into commercial grades of sulfuric acid.

(48) SULFUR RECOVERY PLANT means Units within a Petroleum Refinery, or a separate Facility, that recovers elemental sulfur or sulfur compounds from sour or acid gases and/or sour water generated by Petroleum Refineries.

(49) SULFUR RECOVERY UNITS/TAIL GAS (SRU/TG) INCINERATORS means the thermal or catalytic oxidizer where the residual hydrogen sulfide in the gas exiting the Sulfur Recovery Plant (tail gas) is oxidized to SO_2 before being emitted to the atmosphere.

(50) UNIT means, for the purpose of this rule, any Boilers, Flares, FCCUs, Gas Turbines, Petroleum Coke Calciners, Process Heaters, SMR Heaters, Sulfuric Acid Furnaces, SRU/TG Incinerators, or Vapor Incinerators that requires a South Coast AQMD permit and is not required to comply with a NOx concentration limit in another South Coast AQMD Regulation XI rule.

(51) UNIT BARCT B-CAP ANNUAL EMISSIONS means the remaining estimated annual NOx mass emissions for a Unit that is determined based on the Alternative BARCT NOx Limits, decommissioned Units, and other emission reduction strategies, as calculated pursuant to Attachment B of this rule.

(52) UNIT REDUCTION means the potential NOx emission reduction for a Unit if the NOx emissions for that Unit were reduced from the Representative NOx Concentration to the applicable NOx Concentration Limit in Table 1 based on the Baseline Unit Emissions calculated pursuant to Attachment B of this rule.

(53) UNITS WITH COMBINED STACKS means two or more Units where the flue gas from the Units are combined in one or more common stack(s).

(54) VAPOR INCINERATOR means a thermal oxidizer, afterburner, or other device for burning and destroying air toxics, volatile organic compounds, or other combustible vapors in gas or aerosol form in gas streams and does not include flares.

(d) Concentration Limits

(1) An owner or operator of a Facility shall not operate a Unit that exceeds the applicable NOx and Corresponding CO Concentration Limits in Table 1, pursuant to the compliance schedule in subdivision (f).

TABLE 1: NOx AND CO CONCENTRATION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers <40 MMBtu/hour	Pursuant to subparagraphs (d)(2)(A) and (d)(2)(B)	400	3	24-hour
Boilers ≥40 MMBtu/hour	5	400	3	24-hour
FCCU	2	500	3	365-day
	5			7-day
Flares	20	400	3	2-hour
Gas Turbines fueled with Natural Gas	2	130	15	24-hour
Gas Turbines fueled with Gaseous Fuel other than Natural Gas	3	130	15	24-hour
Petroleum Coke Calciner	5	2,000	3	365-day
	10			7-day
Process Heaters <40 MMBtu/hour	Pursuant to subparagraphs (d)(2)(A) and (d)(2)(C)	400	3	24-hour
Process Heaters ≥40 MMBtu/hour	5	400	3	24-hour
SMR Heaters	5	400	3	24-hour
SMR Heaters with Gas Turbine	5	130	15	24-hour
SRU/TG Incinerators	30	400	3	24-hour
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	30	400	3	24-hour

[1] Averaging times apply to Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule; compliance for Units without a certified CEMS shall be demonstrated pursuant to paragraph (l)(1).

(2) Boilers and Process Heaters Less Than 40 MMBtu/hour

An owner or operator of a Facility shall not operate a Boiler or Process Heater with a Rated Heat Input Capacity less than 40 MMBtu/hour that exceeds the NOx Concentration Limits or Corresponding CO Concentration Limits listed below, pursuant to the compliance schedule in Table 4 – Compliance Schedule for Boilers and Process Heaters Less Than 40 MMBtu/hour (Table 4):

(A) A NOx Concentration Limit of 40 ppmv for a Boiler or Process Heater and the Corresponding CO Concentration Limit in Table 1;

(B) A NOx Concentration Limit of 5 ppmv for a Boiler and the Corresponding CO Concentration Limit in Table 1; and

(C) A NOx Concentration Limit of 9 ppmv for a Process Heater and the Corresponding CO Concentration Limit in Table 1.

(3) Conditional NOx Concentration Limits

An owner or operator of a Facility that elects to meet the conditional NOx and Corresponding CO Concentration Limits in Table 2 for a Unit in lieu of the applicable NOx and Corresponding CO Concentration Limits in Table 1 shall meet the compliance schedule pursuant to paragraph (f)(3) and demonstrate that:

(A) The Executive Officer has not issued a Permit to Construct on or after December 4, 2015 for the installation of post -combustion air pollution control equipment for the Unit;

(B) The Unit Reduction calculated pursuant to Attachment B of this rule is less than 10 tons per year based on the applicable NOx Concentration Limit in Table 1 for a Process Heater with a Rated Heat Input Capacity greater than or equal to 40 MMBtu/hour and less than or equal to 110 MMBtu/hour;

(C) The Unit Reduction calculated pursuant to Attachment B of this rule is less than 20 tons per year based on the applicable NOx Concentration Limit in Table 1 for a Boiler or Process Heater with a Rated Heat Input Capacity greater than 110 MMBtu/hour;

(D) The Permit to Construct or South Coast AQMD Permit to Operate (Permit to Operate) for the Unit does not have a condition that limits the NOx concentration to a level at or below the applicable NOx Concentration Limit in Table 1;

(E) The Representative NOx Concentration of the Unit is not at or below the applicable NOx Concentration Limit in Table 1; and

(F) The Unit is not identified as being decommissioned pursuant to paragraph (f)(10).

TABLE 2: CONDITIONAL NOx AND CO CONCENTRATION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers >110 MMBtu/hour	7.5	400	3	24-hour
FCCUs	8	500	3	365-day
	16			7-day
Gas Turbines fueled with Natural Gas	2.5	130	15	24-hour
Process Heaters ≥40 – ≤110 MMBtu/hour	18	400	3	24-hour
Process Heaters >110 MMBtu/hour	22	400	3	24-hour
SMR Heaters	7.5	400	3	24-hour
Vapor Incinerators	40	400	3	24-hour

[1] Averaging times apply to Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule; compliance for Units without a certified CEMS shall be demonstrated pursuant to paragraph (l)(1).

(4) Gas Turbines

Notwithstanding the NOx Concentration Limit in Table 1, an owner or operator of a Facility shall not operate a Gas Turbine fueled with Natural Gas that exceeds a NOx concentration limit of 5 ppmv at 15 percent O_2 correction based on a 24-hour rolling average during Natural Gas curtailment periods, where there is a shortage in the supply of pipeline Natural Gas due solely to supply limitations or restrictions in distribution pipelines by the utility supplying the gas, and not due to the cost of Natural Gas.

(5) An owner or operator of a Facility with Units With Combined Stacks shall be subject to the most stringent applicable NOx Concentration Limit in Table 1 or Table 2.

(6) An owner or operator of a Facility with a Unit with a CO concentration limit in a Permit to Operate or Permit to Construct that was established before [*DATE OF ADOPTION*], shall meet the CO concentration limit in the Permit to Operate or Permit to Construct in lieu of the applicable Corresponding CO Concentration Limit.

(e) Interim Concentration Limits

(1) An owner or operator of a Former RECLAIM Facility shall not operate a Unit that exceeds the applicable interim NOx Concentration Limit or Corresponding CO Concentration Limit in Table 3 until that Unit is required to meet another NOx concentration limit and CO concentration limit in the rule pursuant to the compliance schedule in subdivision (f) or an approved I-Plan for any:

(A) Unit at a Facility subject to this rule where the owner or operator will meet the NOx and Corresponding CO Concentration Limits in Table 1 or Table 2;

(B) Unit at a Facility subject to this rule where the owner or operator elects to comply with an approved B-Plan; and

(C) Boiler or Process Heater at a Facility less than 40 MMBtu/hour that is not included in a B-Cap, where the owner or operator elects to comply with an approved B-Cap.

TABLE 3: INTERIM NOx AND CO CONCENTRATION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers and Process Heaters <6 MMBtu/hour[2]	60	400	3	365-day
Boilers and Process Heaters ≥6 MMBtu/hour and <40 MMBtu/hour[2]	40	400	3	365-day
Boilers and Process Heaters ≥40 MMBtu/hour	Pursuant to paragraph (e)(2)	400	3	365-day
Flares	105	400	3	365-day
FCCUs	40	500	3	365-day
Gas Turbines fueled with Natural Gas or Other Gaseous Fuel	20	130	15	365-day
Petroleum Coke Calciners	85	2,000	3	365-day
SMR Heaters	20[3]	400	3	365-day
	60[4]			365-day
SMR Heaters with Gas Turbine	5	130	15	365-day
SRU/TG Incinerators	100	400	3	365-day
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	110	400	3	365-day

1 Averaging times are applicable to Units with a CEMS and shall be calculated pursuant to Attachment A of this rule; compliance for Units without a certified CEMS shall be demonstrated pursuant to paragraph (l)(1).

2 Boilers and Process Heaters with a Rated Heat Input Capacity <40 MMBtu/hour that operate with a certified CEMS may comply with the NOx emission limit pursuant to paragraph (e)(2) in lieu of the NOx Concentration Limit in Table 3.

3 SMR Heaters equipped with post-combustion air pollution control equipment that was installed before [*DATE OF ADOPTION*].

4 SMR Heaters not equipped with post-combustion air pollution control equipment as of [*DATE OF ADOPTION*].

(2) An owner or operator of a Former RECLAIM Facility complying with the NOx and Corresponding CO Concentration Limits in Table 1 or Table 2 or that elects to comply with an approved B-Plan shall:

(A) Not exceed an interim facility-wide NOx emission limit of 0.03 pounds/MMBtu based on a daily rolling 365-day average as measured pursuant to subdivision (k), the day after the Facility becomes a Former RECLAIM Facility and everyday thereafter, calculated pursuant to Attachment A Section (A-2) of this rule for:

(i) All Boilers and Process Heaters with a Rated Heat Input Capacity of greater than or equal to 40 MMBtu/hour; or

(ii) All Boilers and Process Heaters with Rated Heat Input Capacity of greater than or equal to 40 MMBtu/hour and Boilers and Process Heaters with Rated Heat Input Capacity of less than 40 MMBtu/hour with a certified NOx CEMS.

(B) Demonstrate compliance with the interim NOx emission rate pursuant to subparagraph (e)(2)(A) until all Boilers and Process Heaters meet the applicable NOx concentration limits in Table 1, Table 2, or an approved B-Plan.

(3) An owner or operator of a Facility with an approved I-Plan and an approved B-Cap shall meet the requirements of subparagraph ~~(h)(6)(D)~~(h)(9)(B) or (h)(9)(C) for Units in the approved B-Cap and shall meet the interim NOx and Corresponding CO Concentration Limits in Table 3 for all other Units.

(f) Compliance Schedule

(1) An owner or operator of a Facility with a Unit that is required to meet the NOx and Corresponding CO Concentration Limits in Table 1 pursuant to subdivision (d), with the exception of Boilers and Process Heaters with a Rated Heat Input Capacity of less than 40 MMBtu/hour, shall:

(A) On or before July 1, 2023, submit a complete permit application for a permit condition that limits the NOx and CO emissions to a level not to exceed the applicable NOx and Corresponding CO Concentration Limits in Table 1; and

(B) Not operate a Unit that exceeds the NOx Concentration Limit or Corresponding CO Concentration Limit pursuant to subparagraph (f)(1)(A) on and after either the date the South Coast AQMD issues the Permit to Operate or 36 months from the date the South Coast AQMD issues a Permit to Construct, whichever is sooner.

(2) An owner or operator of a Facility with a Boiler or Process Heater with a Rated Heat Input Capacity less than 40 MMBtu/hour that is required to meet the NOx and Corresponding CO Concentration Limits pursuant to paragraph (d)(2) shall:

(A) Not operate a Boiler or Process Heater that exceeds the NOx or Corresponding CO Concentration Limits in paragraph (d)(2) pursuant to the compliance schedule in Table 4 unless the Boiler or Process Heater is included in an approved I-Plan;

(B) Submit a complete permit application for a Boiler for a permit condition that limits the NOx and CO emissions to a level not to exceed the NOx and Corresponding CO Concentration Limits pursuant to subparagraph (d)(2)(B) no later than six months after an owner or operator of a Facility cumulatively replaces either 50 percent or more of the burners or replaces burners that represent 50 percent or more of the Heat Input in the Boiler, where the cumulative replacement begins on July 1, 2022; and

(C) Effective [*TEN YEARS AFTER DATE OF ADOPTION*], submit a complete permit application for a Process Heater for a permit condition that limits the NOx and CO emissions to a level not to exceed the NOx and Corresponding CO Concentration Limits pursuant to subparagraph (d)(2)(C) no later than six months after an owner or operator of a Facility cumulatively replaces either 50 percent or more of the burners, or replaces burners that represent 50 percent or more of the Heat Input in the Process Heater, where the cumulative replacement begins [*FIVE YEARS AFTER DATE OF ADOPTION*].

TABLE 4: COMPLIANCE SCHEDULE FOR BOILERS AND PROCESS HEATERS LESS THAN 40 MMBTU/HOUR

Unit	NOx Concentration Limit (ppmv)	Permit Application Submittal Date	Compliance Date
Boilers <40 MMBtu/hour	40 ppmv pursuant to subparagraph (d)(2)(A)	On or before July 1, 2022	• On and after the date the South Coast AQMD issues a Permit to Operate
	5 ppmv pursuant to subparagraph (d)(2)(B)	Pursuant to subparagraph (f)(2)(B)	• On and after 18 months from the date the South Coast AQMD issues a Permit to Construct
Process Heaters <40 MMBtu/hour	40 ppmv pursuant to subparagraph (d)(2)(A)	On or before July 1, 2023	• On and after the date the South Coast AQMD issues the Permit to Operate or on and after 18 months from the date the South Coast AQMD issues a Permit to Construct, whichever is sooner; or • On and after 36 months from the date the South Coast AQMD issues a Permit to Construct if the owner or operator of a Facility elects to meet the NOx Concentration Limit pursuant to subparagraph (d)(2)(C) in lieu of subparagraph (d)(2)(A)
	9 ppmv pursuant to subparagraph (d)(2)(C)	Pursuant to subparagraph (f)(2)(C)	• On and after 18 months from the date the South Coast AQMD issues a Permit to Construct

(3) Table 2 Conditional Concentration Limits

An owner or operator of a Facility that meets the conditions in paragraph (d)(3) to meet the conditional NOx and Corresponding CO Concentration Limits in Table 2 in lieu of the NOx and Corresponding CO Concentration Limits in Table 1 shall:

(A) On or before June 1, 2022, submit a complete permit application for a permit condition that limits the NOx and CO emissions to a level not to exceed the applicable conditional NOx and Corresponding CO Concentration Limits in Table 2 and provide documentation that the requirements in paragraph (d)(3) have been met; and

(B) Not operate a Unit that exceeds the applicable conditional NOx Concentration Limit or Corresponding CO Concentration Limit in Table 2 on and after either the date the South Coast AQMD issues the Permit to Operate or 18 months from the date the South Coast AQMD issues a Permit to Construct, whichever is sooner.

(4) An owner or operator of a Facility that replaces existing NOx control equipment on a Unit complying with a conditional NOx and Corresponding CO Concentration Limit in Table 2 shall:

(A) Submit a complete permit application for a permit condition that limits the NOx and CO emissions to a level not to exceed the applicable NOx and Corresponding CO Concentration Limits in Table 1 prior to the date of replacing the existing NOx control equipment. Replacement of the existing NOx control equipment will be determined as:

(i) Replacement of existing post-combustion air pollution control equipment on a FCCU, Gas Turbine fueled with Natural Gas, Process Heater with a Rated Heat Input Capacity of greater than or equal to 40 MMBtu/hour, or SMR Heater;

(ii) Replacement of components on existing post-combustion air pollution control equipment on any Unit listed in clause (f)(4)(A)(i) where the fixed capital cost of the new components for the post-combustion air pollution control equipment exceeds 50 percent of the fixed capital cost that would be required to construct and install a comparable new post-combustion air pollution control equipment; or

(iii) 50 percent or more of the burners in a Vapor Incinerator, or 50 percent or more of the Rated Heat Input Capacity of the burners in a Vapor Incinerator, are cumulatively replaced after [*DATE OF ADOPTION*];

(B) Not operate a Unit that exceeds the NOx or CO concentration limits pursuant to subparagraph (f)(4)(A) on and after either the date the South Coast AQMD issues the Permit to Operate or 18 months from the date the South Coast AQMD issues a Permit to Construct, whichever is sooner.

(5) An owner or operator of a Facility with a Unit that is exempt pursuant to paragraph (o)(2), (o)(3), (o)(5), (o)(6), (o)(8), or (o)(9) shall:

(A) On or before July 1, 2022, submit a complete permit application to apply for a permit condition that limits the NOx emissions, Rated Heat Input Capacity, Heat Input, or operating hours pursuant to the applicable limits in subparagraph (o)(2)(A), (o)(3)(A), (o)(5)(A), or (o)(6)(A), or clause (o)(8)(A)(i), (o)(9)(A)(i) or (o)(9)(B)(i); and

(B) Not operate a Unit that exceeds the limits pursuant to subparagraph (f)(5)(A) on and after the date the South Coast AQMD issues a Permit to Operate.

(6) An owner or operator of a Facility with a Unit exempt from the NOx and Corresponding CO Concentration Limits in Table 1 pursuant to paragraph (o)(2), (o)(3), (o)(5), (o)(6), (o)(8), or (o)(9) that exceeds the applicable exemption limitations shall:

(A) Within six months of the exceedance, submit a complete permit application to apply for a permit condition that limits the NOx and CO emissions to a level not to exceed the applicable NOx and Corresponding CO Concentration Limit in Table 1; and

(B) Not operate a Unit that exceeds the NOx or CO concentration limits pursuant to subparagraph (f)(6)(A) on and after either the date the South Coast AQMD issues the Permit to Operate or 18 months from the date the South Coast AQMD issues the Permit to Construct, whichever is sooner.

(7) An owner or operator of a Facility that fails to submit a permit application on or before:

(A) The date specified in subparagraph (f)(1)(A), shall expeditiously submit a complete permit application and meet the applicable NOx and Corresponding CO Concentration Limits in Table 1 no later than 36 months after the permit application submittal deadline pursuant to subparagraph (f)(1)(A);

(B) The date specified in subparagraph (f)(3)(A) or (f)(4)(A), shall expeditiously submit a complete permit application and meet the applicable NOx and Corresponding CO Concentration Limits in Table 1 no later than 24 months after the respective permit application submittal deadline pursuant to subparagraph (f)(3)(A) or (f)(4)(A); or

(C) The date specified in Table 4 for Boilers subject to the 5 ppmv limits and all Process Heaters, shall expeditiously submit a complete permit application and meet the applicable NOx and Corresponding CO Concentration Limits pursuant to paragraph (d)(2) no later than 24 months after the applicable permit application submittal deadline pursuant to Table 4.

(8) An owner or operator of a Facility with a Unit subject to an averaging time less than a 365-day rolling average that operates a certified CEMS shall be required to demonstrate compliance with the applicable NOx Concentration Limit or Alternative BARCT NOx Limit, and Corresponding CO Concentration Limit six months after the date the Permit to Operate is issued, 36 months after the Permit to Construct is issued, or immediately after completion of the initial NOx compliance demonstration pursuant to paragraph (l)(4), whichever is soonest.

(9) An owner or operator of a Facility with a Unit subject to a 365-day rolling average shall demonstrate compliance with the applicable NOx Concentration Limit or Alternative BARCT NOx Limit, and Corresponding CO Concentration Limit beginning 14 months after the date the Permit to Operate is issued, 36 months after the Permit to Construct is issued, or immediately after completion of the initial NOx compliance demonstration pursuant to paragraph (l)(4), whichever is soonest.

(10) Decommissioned Units

(A) An owner or operator that decommissions a Unit to meet the requirements of this rule shall:

(i) Surrender the Permit to Operate of the Unit to be decommissioned, pursuant to the schedule in subparagraph (f)(10)(B);

(ii) Disconnect and blind the fuel line(s) of the Unit to be decommissioned, pursuant to the schedule in subparagraph (f)(10)(B); and

(iii) Not sell the decommissioned Unit to another entity for operation within the South Coast Air Basin.

(B) An owner or operator shall meet the requirements of clauses (f)(10)(A)(i) and (f)(10)(A)(ii):

(i) No later than 54 months from Permit Application Submittal Date for Phase I specified in Table 6 for the I-Plan option selected, if a Unit is excluded from a B-Plan pursuant to clause (g)(1)(B)(ii);

(ii) No later than the date specified by the Executive Officer, if an approved B-Plan is modified to remove a Unit that will be decommissioned;

(iii) No later than 90 days from commissioning a New Unit, if the New Unit is replacing in whole or in part a Unit to be decommissioned to meet the requirements of an approved B-Cap and an approved I-Plan; or

(iv) No later than the B-Cap Effective Date of the Facility BARCT Emission Target specified in Table 6 for the I-Plan option selected for a B-Cap, if a Unit is to be decommissioned to meet the requirements of an approved B-Cap and an approved I-Plan and a New Unit is not replacing the Unit to be decommissioned.

(g) B-Plan and B-Cap Requirements

(1) An owner or operator of a Facility with six or more Units subject to this rule that elects to implement an approved B-Plan in lieu of meeting the NOx Concentration Limits in Table 1 or Table 2 shall:

(A) Submit a complete B-Plan to the Executive Officer for review pursuant to subdivision (i).

(B) Include all Units subject to this rule with the option to exclude:

(i) Optional Units;

(ii) Any Unit that will be decommissioned on or before 54 months from the Permit Application Submittal Date in Phase I of the selected I-Plan option in Table 6; and

(iii) Any Unit listed under paragraphs (o)(2), (o)(3), (o)(5), (o)(6), (o)(8), and (o)(9), and Units listed in paragraph (o)(1) shall not be included in the B-Plan.

(C) Calculate the Phase I, Phase II, or if applicable, Phase III BARCT Equivalent Mass Emissions, pursuant to Attachment B, where the owner or operator of a Facility shall:

(i) Select an Alternative BARCT NOx Limit, based on the applicable percent O_2 correction and averaging period specified in Table 1, for each Unit included in the B-Plan;

(ii) Limit the Alternative BARCT NOx Limit to the applicable conditional NOx Concentration Limit in Table 2, for any Unit that meets the conditions in paragraph (d)(3) and the permit submittal deadline in subparagraph (f)(3)(A);

(iii) Use the Representative NOx Concentration for any Unit where an Alternative BARCT NOx Limit is not specified; and

(iv) Demonstrate that an Alternative BARCT NOx Limit has been specified for each Unit in the I-Plan by the final phase of the selected I-Plan.

(2) Upon receiving approval of an I-Plan and a B-Plan pursuant to paragraph (i)(4), the owner or operator of a Facility shall:

(A) Submit a complete permit application for each Unit in the approved B-Plan to apply for a permit condition that limits the NOx emissions to a level not to exceed the Alternative BARCT NOx Limit pursuant to subparagraph (g)(1)(C) and the Corresponding CO Limits in Table 1, pursuant to the schedule in the approved I-Plan; and

(B) Not operate a Unit that exceeds the Alternative BARCT NOx Limit pursuant to subparagraph (g)(2)(A) pursuant to the schedule in the approved I-Plan.

(3) An owner or operator of a Facility with six or more Units subject to this rule that elects to implement an approved B-Cap in lieu of meeting the NOx Concentration Limits in Table 1 and/or Table 2, shall:

(A) Submit a complete B-Cap to the Executive Officer for review pursuant to subdivision (i).

(B) Include all Units subject to this rule with the option to exclude:

(i) Optional Units; ~~and~~

(ii) Vapor Incinerators with a Rated Heat Input Capacity less than 5 MMBtu/hour provided the Vapor Incinerator has an NOx concentration limit in an existing permit that is at or below the applicable NOx concentration limit in Table 2 and the permit was issued prior to [*DATE OF ADOPTION*]; and

(~~ii~~iii) Any Unit listed under paragraphs (o)(2), (o)(5), (o)(6), (o)(8), and (o)(9), and Units listed in paragraph (o)(1) shall not be included in the B-Cap.

(C) Calculate the Phase I, Phase II, or if applicable, Phase III BARCT Equivalent Mass Emissions, pursuant to Attachment B of this rule, where the owner or operator of a Facility shall:

(i) Select an Alternative BARCT NOx Limit, based on the applicable percent O_2 correction and averaging period specified in Table 1, for each Unit included in the B-Cap where the Alternative BARCT NOx Limit shall not exceed:

(A) The applicable NOx Concentration Limit in Table 5; and

(B) The applicable conditional NOx Concentration Limit in Table 2, for any Unit that meets the conditions in paragraph (d)(3) and the permit submittal deadline in subparagraph (f)(3)(A);

(ii) Use the Representative NOx Concentration for any Unit where an Alternative BARCT NOx Limit is not specified; and

(iii) Demonstrate that an Alternative BARCT NOx Limit has been specified for each Unit in the I-Plan by the final phase of the selected I-Plan.

(D) Calculate the Phase I, Phase II, and if applicable, Phase III BARCT B-Cap Annual Emissions, pursuant to Attachment B of this rule, where the Unit BARCT B-Cap Annual Emissions can include emission reductions from:

(i) The Alternative BARCT NOx Limit;

(ii) Any decommissioned Unit(s); or

(iii) Other emission reduction strategies.

(4) Upon receiving approval of an I-Plan and B-Cap pursuant to paragraph (i)(4), the owner or operator of a Facility shall:

(A) Submit a complete permit application for each Unit in the approved B-Cap to apply for a permit condition that limits the NOx emissions to a level not to exceed the Alternative BARCT NOx Limit pursuant to subparagraph (g)(3)(C) and the Corresponding CO Limits in Table 1, pursuant to the schedule in the approved I-Plan;

(B) Not operate a Unit that exceeds the Alternative BARCT NOx Limit pursuant to the subparagraph (g)(4)(A) pursuant to the schedule in the approved I-Plan;

(C) Meet the requirements specified in subparagraph (f)(10)(A) for any Unit that is identified in an approved I-Plan to be decommissioned based on the schedule in subparagraph (f)(10)(B);

(D) Not operate any Unit unless the NOx emissions for all Units in the approved B-Cap are in aggregate at or below the applicable Phase I, Phase II, or if applicable, Phase III Facility BARCT Emission Target pursuant to paragraph (h)(6); and

(E) Demonstrate that at least one of the following conditions is met if a New Unit is added to the Facility and provide in writing at the time the permit application is submitted to the Executive Officer for the New Unit which of the following condition(s) are met:

(i) The unit for which permit application is being submitted is not subject to this rule or is a Unit that is complying with an exemption pursuant to paragraph (o)(1), (o)(2), (o)(3), (o)(5), (o)(6), (o)(8), or (o)(9);

(ii) The BARCT Equivalent Mass Emissions with the New Unit is below the Facility BARCT Emission Target for the current and any future phase of the I-Plan, as calculated in Attachment B of this rule;

(iii) The New Unit is not Functionally Similar to any Unit that was decommissioned in the approved B-Cap and the New Unit will not increase the overall facility throughput;

(iv) The total amount of NOx emission reductions from units that were decommissioned, represents 15 percent or less of the Final Phase Facility BARCT Emission Target in an approved B-Cap and the B-Cap is modified to include the

New Unit and the Facility BARCT Emission Target is adjusted to incorporate the New Unit; or

(v) The New Unit is Functionally Similar to any Unit that was decommissioned and the B-Cap is modified with no increase of the Facility BARCT Emission Target.

TABLE 5: MAXIMUM ALTERNATIVE BARCT NOx CONCENTRATION LIMITS FOR A B-CAP

Unit	Maximum Alternative BARCT NOx Limit	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers and Process Heaters <40 MMBtu/hour	40 ppmv	3	24-hour
Boilers and Process Heaters ≥40 MMBtu/hour	50 ppmv	3	24-hour
FCCUs	8 ppmv	3	365-day
	16 ppm		7-day
Gas Turbines	5 ppmv	15	24-hour
Petroleum Coke Calciners	100 tons/year	N/A	365-day
SMR Heaters	12 ppm	3	24-hour
SRU/TG Incinerators	100 ppmv	3	24-hour
Vapor Incinerators	40 ppmv	3	24-hour

[1] Averaging times apply to Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule; compliance for Units without a certified CEMS shall be demonstrated pursuant to paragraph (l)(1).

(h) I-Plan Requirements

(1) An owner or operator of a Facility with six or more Units subject to this rule that elects to implement an I-Plan in lieu of meeting the compliance schedule specified in paragraph (f)(1) shall:

(A) Submit a complete I-Plan to the Executive Officer pursuant to paragraph (i)(1);

(B) Include all Units in the I-Plan that are:

(i) Included in an accompanying B-Plan pursuant to subparagraph (g)(1)(B);

(ii) Included in an accompanying B-Cap pursuant to subparagraph (g)(3)(B); or

(iii) For an owner or operator that is not submitting a B-Cap or a B-Plan, include all Units subject to this rule with the option to exclude:

(A) Optional Units; and

(B) Any Unit listed under paragraphs (o)(2), (o)(5), (o)(6), (o)(8), and (o)(9), and Units listed in paragraph (o)(1) shall not be included in the I-Plan; and

(C) Any Unit included in the I-Plan shall be located at either a single Facility or Facilities With The Same Ownership.

(2) An owner or operator that elects to implement an I-Plan shall select one I-Plan Option from Table 6 where the selection of:

(A) I-Plan Option 1 and I-Plan Option 5 shall be allowed if an owner or operator is implementing a B-Plan or complying with the NOx Concentration Limits in Table 1 or Table 2;

(B) I-Plan Option 2 shall be allowed if an owner or operator is implementing a B-Plan;

(C) I-Plan Option 3 shall be allowed if an owner or operator is implementing a B-Plan or a B-Cap;

(D) I-Plan Option 4 shall be allowed only if an owner or operator is implementing a B-Cap; and

(E) I-Plan Option 2 and I-Plan Option 3 shall be allowed only if an owner or operator of a Facility is achieving a NOx emission rate of less than 0.02 pound/MMBtu of Heat Input, based on annual emissions for the applicable Units as reported in the 2021 Annual Emissions Report and calculated pursuant to Attachment A, for all the Boilers and Process Heaters with Rated Heat Input Capacity of greater than or equal to 40 MMBtu/hour based on the maximum Rated Heat Input Capacity by [*DATE OF ADOPTION*].

**TABLE 6: I-PLAN PERCENT REDUCTION TARGETS
OF REQUIRED REDUCTIONS AND COMPLIANCE SCHEDULE**

<table>
<tr><th>I-Plan Option</th><th>Key Elements</th><th>Phase I</th><th>Phase II</th><th>Phase III</th></tr>
<tr><td rowspan="3">I-Plan Option 1 for B-Plan or Concentration Limits in Table 1 or Table 2</td><td>Percent Reduction Targets</td><td>80</td><td>100</td><td>N/A</td></tr>
<tr><td>Permit Application Submittal Date</td><td>January 1, 2023</td><td>January 1, 2031</td><td>N/A</td></tr>
<tr><td>Compliance Schedule</td><td colspan="2">No later than 36 months after a Permit to Construct is issued</td><td>N/A</td></tr>
<tr><td rowspan="3">I-Plan Option 2 for B-Plan Only pursuant to subparagraph (h)(2)(E)</td><td>Percent Reduction Targets</td><td>65</td><td>100</td><td>N/A</td></tr>
<tr><td>Permit Application Submittal Date</td><td>July 1, 2024</td><td>January 1, 2030</td><td>N/A</td></tr>
<tr><td>Compliance Schedule</td><td colspan="2">No later than 36 months after a Permit to Construct is issued</td><td>N/A</td></tr>
<tr><td rowspan="4">I-Plan Option 3 for B-Plan or B-Cap pursuant to subparagraph (h)(2)(E)</td><td>Percent Reduction Targets</td><td>40</td><td>100</td><td>N/A</td></tr>
<tr><td>Permit Application Submittal Date</td><td>July 1, 2025</td><td>July 1, 2029</td><td>N/A</td></tr>
<tr><td>Compliance Schedule</td><td colspan="2">No later than 36 months after a Permit to Construct is issued</td><td>N/A</td></tr>
<tr><td>B-Cap Effective Date of the Facility BARCT Emission Target</td><td>January 1, 2030</td><td>January 1, 2034</td><td>N/A</td></tr>
<tr><td rowspan="4">I-Plan Option 4 for B-Cap Only</td><td>Percent Reduction Targets</td><td>50</td><td>80</td><td>100</td></tr>
<tr><td>Permit Application Submittal Date</td><td>N/A</td><td>January 1, 2025</td><td>January 1, 2028</td></tr>
<tr><td>Compliance Schedule</td><td>January 1, 2024</td><td colspan="2">No later than 36 months after a Permit to Construct is issued</td></tr>
<tr><td>B-Cap Effective Date of the Facility BARCT Emission Target</td><td>January 1, 2024</td><td>July 1, 2029</td><td>July 1, 2032</td></tr>
<tr><td rowspan="3">I-Plan Option 5 for B-Plan Only or Concentration Limits in Table 1 or Table 2</td><td>Percent Reduction Targets</td><td>50</td><td>70</td><td>100</td></tr>
<tr><td>Permit Application Submittal Date</td><td>January 1, 2023</td><td>January 1, 2025</td><td>July 1, 2028</td></tr>
<tr><td>Compliance Schedule</td><td colspan="3">No later than 36 months after a Permit to Construct is issued</td></tr>
</table>

(3) An owner or operator that elects to implement an I-Plan shall use the Baseline NOx Emissions and Representative NOx Concentrations listed in "Baseline NOx Emissions and Representative NOx Concentrations for Facilities Regulated Under Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations" that was approved on [*DATE OF ADOPTION*]. An owner or operator may use another value for the Baseline NOx Emissions and Representative NOx Concentration for a Unit, provided:

(A) Within 30 days of [*DATE OF ADOPTION*], the owner or operator submits a request in writing to the Executive Officer a change to the Baseline NOx Emissions or Representative NOx Concentration for the Unit, providing the Device ID of the Unit;

(B) The Executive Officer approves the change as it more accurately represents the Baseline NOx Emissions or the Representative NOx Concentration considering annual emissions data, CEMS data, source test data, and any other documentation that substantiates the change; and

(C) Any change to the Baseline NOx Emissions or Representative NOx Concentration that is greater than 5 percent of the corresponding value for the Unit is presented to the Stationary Source Committee no later than February 18, 2022.

(4) An owner or operator of a Facility that elects to implement an I-Plan shall calculate the Facility BARCT Emission Target for each phase, and incorporate an additional 10 percent NOx reduction to Final Phase Facility Emission Target for a B-Cap, and calculate the Final Phase Facility BARCT Emission Target, pursuant to Attachment B of this rule using:

(A) For an owner or operator that does not select I-Plan Option 4, the applicable conditional NOx Concentration Limit in Table 2 for each Unit that:

(i) Meets the conditions in paragraph (d)(3) and a permit application was submitted pursuant to subparagraph (f)(3)(A); or

(ii) Is listed in Table D-1 – Process Heaters and Boilers greater than 40 MMBTU/hr That Qualify for Conditional Limits in B-Plan or B-Cap (Table D-1) in Attachment D of this rule;

(B) For an owner or operator submitting a B-Cap that selects I-Plan Option 4, the applicable conditional NOx Concentration Limit in Table 2 for each Unit listed in Table D-2 – ~~Process Heaters and Boilers >40 MMBTU/hr~~Units That Qualify for Conditional Limits in ~~B-Plan or~~ B-Cap using I-Plan Option 4 (Table D-2) in Attachment D of this rule;

(C) 5 ppmv for any Boiler with a Rated Heat Input Capacity less than 40 MMBtu/hour;

(D) 40 ppmv for a Process Heater with a Rated Heat Input Capacity less than 40 MMBtu/hour with a Representative NOx Concentration greater than or equal to 75 ppmv, provided:

(i) The Unit will achieve a NOx concentration limit at or below 40 ppmv in Phase I of an I-Plan; and

(ii) Any additional NOx emission reductions beyond those achieved to meet clause (h)(4)(D)(i) are not used to meet the Facility BARCT Emission Target for Phase II, or if applicable, Phase III of an I-Plan;

(E) 9 ppmv for any Process Heaters with a Rated Heat Input Capacity of less than 40 MMBtu/hour with a Representative NOx Concentration less than 75 ppmv; and

(F) The applicable NOx Concentration Limits in Table 1 for all other Units, including any Unit that will be decommissioned under a B-Cap.

(5) An owner or operator of a Facility that elects to implement an I-Plan and a B-Plan, or an I-Plan to meet the NOx Concentration Limits and Corresponding CO Concentration Limits in Table 1 or Table 2 shall demonstrate that the Phase I, Phase II, and if applicable, Phase III BARCT Equivalent Mass Emissions are less than the respective Phase I, Phase II, or if applicable, Phase III Facility BARCT Emission Target.

(6) An owner or operator of a Facility that elects to implement an I-Plan and a B-Cap shall demonstrate that the Phase I, Phase II, and if applicable, Phase III BARCT B-Cap Annual Emissions are less than the respective Phase I, Phase II, or Phase III Facility BARCT Emission Target.

(7) Upon receiving approval of an I-Plan pursuant to paragraph (i)(4), without a B-Plan or B-Cap pursuant, an owner or operator of a Facility shall meet

the NOx Concentration Limits and Corresponding CO Concentration Limits in Table 1 or Table 2.

(8) Upon receiving approval of an I-Plan and a B-Plan pursuant to paragraph (i)(4), an owner or operator of a Facility shall meet the Alternative BARCT NOx Concentration Limits in an approved B-Plan to achieve the Facility BARCT Emission Target for each phase, based on the schedule in the approved I-Plan.

(9) Upon receiving approval of an I-Plan and a B-Cap pursuant to paragraph (i)(4), the owner or operator of a Facility shall:

(A) Meet the Alternative BARCT NOx Limit and decommission any Unit in an approved B-Cap, and implement other emission reduction strategies to achieve the Facility BARCT Emission Target for each phase, based on the schedule in the approved I-Plan;

(B) For I-Plan option 3, demonstrate daily compliance that the total NOx mass emissions from all Units in the I-Plan are below the Phase I, Phase II, and if applicable, Phase III Facility BARCT Emission Target, based on a 365-day rolling average as measured pursuant to subdivision (k) or subparagraph (n)(2)(C), where the Facility BARCT Emission Target is:

(i) The Baseline Facility Emissions before January 1, 2031, only if the Facility is a Former RECLAIM Facility;

(ii) Phase I Facility BARCT Emission Target on and after January 1, 2031 and before January 1, 2035; and

(iii) Phase II Facility BARCT Emission Target on and after January 1, 2035; and

(C) For I-Plan option 4, demonstrate daily compliance that the total NOx mass emissions from all Units in the I-Plan are below the Phase I, Phase II, and if applicable, Phase III Facility BARCT Emission Target, based on a 365-day rolling average as measured pursuant to subdivision (k) or subparagraph (n)(2)(C), where the Facility BARCT Emission Target is:

(i) The Baseline Facility Emissions before January 1, 2025, only if the Facility is a Former RECLAIM Facility;

(ii) Phase I Facility BARCT Emission Target on and after January 1, 2025 and before July 1, 2030;

(iii) Phase II Facility BARCT Emission Target on and after July 1, 2030 and before July 1, 2033; and

(iv) Phase III Facility BARCT Emission Target on and after July 1, 2033.

(i) I-Plan, B-Plan, and B-Cap Submittal and Approval Requirements

(1) I-Plan Submittal Requirements

On or before September 1, 2022, an owner or operator of a Facility that elects to implement an approved I-Plan pursuant to subdivision (h) shall submit a complete I-Plan to the Executive Officer for review that:

(A) Identifies each Unit required to be included in the I-Plan pursuant to subparagraph (h)(1)(B), and includes the device identification number with a description of each Unit;

(B) Identifies all Facilities With The Same Ownership, by facility identification number, subject to the rule that are included in the I-Plan pursuant to subparagraph (h)(1)(C);

(C) Identifies the anticipated start and end date (month and year) of the turnaround schedule for each Unit;

(D) Specifies the selected I-Plan option that meets the requirements of paragraph (h)(2);

(E) Calculates the Phase I, Phase II, and if applicable, Phase III Facility BARCT Emission Targets pursuant to Attachment B of this rule using the NOx concentration limit for each Unit pursuant to paragraph (h)(4) and incorporates the additional 10 percent NOx emission reduction pursuant to paragraph (h)(4) for an owner or operators of a Facility submitting a B-Cap;

(F) Calculates the BARCT Equivalent Mass Emissions using the Alternative BARCT NOx Limits pursuant to Attachment B of this rule;

(G) Demonstrates that the Mass Emissions for all Units in each phase are less than or equal to the respective phase of the Facility BARCT Emission Target in an I-Plan as calculated pursuant to Attachment B of this rule, for an owner or operator that is submitting an I-Plan without a B-Plan or a B-Cap;

(H) Demonstrates that each phase of the BARCT Equivalent Mass Emissions are less than the respective phase of the Facility BARCT

Emission Target, pursuant to paragraph (h)(5), for owners or operators that are submitting a B-Plan; and

(I) Demonstrates that each phase of the BARCT B-Cap Annual Emissions is less than the respective phase of the Facility BARCT Emission Target, pursuant to paragraph (h)(6), where the Final Phase Facility BARCT Emission Target is reduced by 10 percent pursuant to paragraph (h)(4), for owners or operators that are submitting a B-Cap.

(2) B-Plan Submittal Requirements

On or before September 1, 2022, an owner or operator of a Facility that elects to implement an approved B-Plan pursuant to paragraph (g)(1), shall submit a complete B-Plan to the Executive Officer for review that:

(A) Identifies each Unit required to be included in the B-Plan pursuant to subparagraph (g)(1)(B), and includes the device identification number with a description of each Unit;

(B) Specifies the Alternative BARCT NOx Limits for each Unit of the I-Plan that meets the requirements of subparagraph (g)(1)(C);

(C) Calculates the Phase I, Phase II, and if applicable, Phase III BARCT Equivalent Mass Emissions using the Alternative BARCT NOx Limits identified in subparagraph (i)(2)(B), as calculated pursuant to Attachment B of this rule;

(D) Specifies which phase or phases in the I-Plan each permit application will be submitted for each Unit subject to the B-Plan to meet the Alternative BARCT NOx Concentrations pursuant to subparagraph (g)(2)(A); and

(E) Specifies each Unit that has an existing permit condition that limits the NOx concentration to the Alternative BARCT NOx Limit.

(3) B-Cap Submittal Requirements

On or before September 1, 2022, an owner or operator of a Facility that elects to implement an approved B-Cap pursuant to paragraph (g)(3), shall submit a complete B-Cap to the Executive Officer for review that:

(A) Identifies each Unit required to be in the B-Cap pursuant to subparagraph (g)(3)(B), and includes the device identification number with a description of the Unit;

(B) Specifies the Alternative BARCT NOx Limits for each Unit of the I-Plan that meets the requirements of subparagraph (g)(3)(C);

(C) Calculates the Phase I, Phase II, and if applicable, Phase III BARCT Equivalent Mass Emissions using the Alternative BARCT NOx Limits identified in subparagraph (i)(3)(B), as calculated pursuant to Attachment B of this rule;

(D) Calculates the Phase I, Phase II, and if applicable Phase III BARCT B-Cap Annual Emissions pursuant to subparagraph (g)(3)(D);

(E) Provide an explanation when the Unit BARCT B-Cap Annual Emissions are less than the BARCT Equivalent Mass Emissions for any Unit;

(F) Specifies which phase or phases in the I-Plan each permit application will be submitted for each Unit subject to the B-Cap to meet the Alternative BARCT NOx Concentrations pursuant to subparagraph (g)(4)(A);

(G) Specifies each Unit that has an existing permit condition that limits the NOx concentration to the Alternative BARCT NOx Limit;

(H) Identifies any Unit that will be decommissioned, and the phase of the I-Plan that the Unit will be decommissioned; and

(I) Identifies any Unit that will have other reductions in mass emissions for each phase of the approved I-Plan.

(4) I-Plan, B-Plan, and B-Cap Review and Approval Process

The Executive Officer will notify the owner or operator of a Facility in writing whether the I-Plan, B-Plan, or B-Cap is approved or disapproved. An I-Plan, B-Plan, or B-Cap shall be approved if the following criteria is met, and they are subject to disapproval if any of the following, applicable criteria are not met:

(A) The owner or operator submitted a complete I-Plan, B-Plan, and B-Cap on or before September 1, 2022, and the I-Plan contains information required in paragraph (i)(1), the B-Plan contains information required in paragraph (i)(2), and the B-Cap contains information required in paragraph (i)(3);

(B) Units included in the I-Plan, B-Plan, and B-Cap meet the requirements of subparagraphs (h)(1)(B) and all Units are either located at a Facility or Facilities With The Same Ownership pursuant to subparagraph (h)(1)(C);

(C) The I-Plan option selected meets the requirements of paragraph (h)(2);

(D) The Baseline NOx Emissions and Representative NOx Concentrations for each Unit, used to calculate the Final Phase Facility BARCT Emission Target, the Facility BARCT Emission Targets, the BARCT Mass Emissions, the BARCT Equivalent Mass Emissions, the BARCT B-CAP Annual Emissions, the Emission Reductions from Decommissioned Units and Unit Reductions, or any other emissions calculation for the I-Plan, B-Plan, or B-Cap, meets the requirements specified in paragraph (h)(3);

(E) The BARCT Equivalent Mass Emissions were calculated pursuant to Attachment B and the Alternative BARCT NOx Limit selected meets the requirements of subparagraph (g)(1)(C) for a B-Plan and subparagraph (g)(3)(C) for a B-Cap;

(F) The Facility BARCT Emission Target for each phase was calculated pursuant to Attachment B, and the Final Phase Facility BARCT Emission Target was calculated pursuant to Attachment B using the NOx concentration limit for each Unit pursuant to paragraph (h)(4);

(G) For an I-Plan and a B-Plan, or an I-Plan to meet NOx Concentration Limits in Table 1 or Table 2, the Phase I, Phase II, and if applicable, Phase III BARCT Equivalent Mass Emissions are less than the respective Phase I, Phase II, or if applicable, Phase III Facility BARCT Emission Target pursuant to paragraph (h)(5); and

(H) The Phase I, Phase II, and if applicable, Phase III BARCT B-Cap Annual Emissions for a B-Cap are less than the respective Phase I, Phase II, or if applicable, Phase III Facility BARCT Emission Target that incorporates an additional 10 percent NOx emission reduction pursuant to paragraph (h)(4).

(5) Within 45 days of receiving written notification from Executive Officer that the I-Plan, B-Plan, or B-Cap is disapproved, the owner or operator shall correct any deficiencies and re-submit the I-Plan, B-Plan, or B-Cap.

(6) Upon receiving written notification from the Executive Officer that the I-Plan, B-Plan, or B-Cap re-submitted pursuant to paragraph (i)(5) is disapproved, the owner or operator shall comply with the NOx Concentration Limits in Table 1 or Table 2 pursuant to the compliance schedule and Percent Reduction Targets in the selected I-Plan option.

(7) Modifications to an Approved I-Plan, an Approved B-Plan, and an Approved B-Cap

An owner or operator of a Facility that seeks approval to modify an approved I-Plan, an approved B-Plan, or an approved B-Cap shall:

(A) Submit a request in writing to the Executive Officer to modify an Approved I-Plan, an Approved B-Plan, and an Approved B-Cap that includes all the plan submittal requirements pursuant to paragraph (i)(1) for an approved I-Plan, paragraph (i)(2) for an approved B-Plan, or paragraph (i)(3) for an approved B-Cap; and

(B) Modify an approved I-Plan, B-Plan, or B-Cap if:

(i) A Unit identified as qualifying for a conditional NOx Concentration Limit in Table 2 no longer meets the requirements pursuant to paragraph (d)(3);

(ii) A Unit in an approved B-Cap identified as qualifying for the conditional NOx Concentration Limit in Table 2 for establishing the Phase I, Phase II, or Phase III BARCT Facility Emission Target is decommissioned or a Unit in an approved B-Plan is decommissioned;

(iii) A higher Alternative BARCT NOx Limit will be proposed in the complete permit application than the Alternative BARCT NOx Limit for that Unit in an approved I-Plan, an approved B-Plan, or an approved B-Cap;

(iv) Any emission reduction project is moved to a later implementation phase, any emission reduction project is moved between phases, or any emission reduction project is removed from a phase;

(v) The owner or operator receives a written notification from the Executive Officer that modifications to the I-Plan, B-Plan, or B-Cap are needed; or

(vi) The owner or operator of a Facility with an approved B-Cap submits a permit application for a Permit to Construct for a New Unit that meets at least one of the provisions pursuant to subparagraph (g)(4)(E).

(8) The Executive Officer will review any modifications to an I-Plan, B-Plan, or B-Cap in accordance with the review and approval process pursuant to paragraph (i)(4).

(9) Notification of Pending Approval of an I-Plan, B-Plan, or B-Cap

The Executive Officer will make the proposed I-Plan, B-Plan, or B-Cap or proposed modifications to an approved I-Plan, an approved B-Plan, or an approved B-Cap available to the public on the South Coast AQMD website 30 days prior to approval.

(10) Plan Fees

The review and approval of an I-Plan, B-Plan, and B-Cap, or review and approval of a modification of an approved I-Plan, an approved B-Plan, and an approved B-Cap shall be subject to applicable plan fees pursuant to Rule 306 – Plan Fees.

(11) An I-Plan, B-Plan, or B-Cap shall be subject to Rule 221 – Plans.

(j) Time Extensions

(1) An owner or operator of a Facility may request a one-time 12-month extension from the compliance schedule in subparagraph (f)(1)(B) or in an approved I-Plan, for each unit, to meet the NOx Concentration Limit and Corresponding CO Concentration Limit or the Alternative BARCT NOx Concentration Limit for specific circumstances, provided:

(A) The complete permit application for the Unit was submitted on or before the date specified in paragraph (f)(1) or the approved I-Plan; and

(B) The specific reasons to necessitate an extension of time are outside of the control of the owner or operator.

(2) An owner or operator of a Facility may request, a one-time time extension from the compliance schedule in an approved I-Plan, for each Unit, to meet the NOx Concentration Limit and Corresponding CO Concentration Limit or an Alternative BARCT Concentration Limit to accommodate the Units scheduled turnaround date provided:

(A) The complete permit application for the Unit was submitted on or before the date specified in the approved I-Plan;

(B) The month and year of the scheduled turnaround and the month and year of the subsequent turnaround for the Unit is submitted in writing at the time of complete permit application submittal; and

(C) The Permit to Construct for the Unit was issued after the scheduled turnaround date or more than 18 months after the complete permit application was submitted, provided:

(i) The scheduled turnaround date was between 18 and 54 months after the complete permit application was submitted and the subsequent scheduled turnaround for the Unit will not occur until 12 months after the compliance schedule in the approved I-Plan; or

(ii) The subsequent scheduled turnaround for the Unit will occur more than 48 months after the Permit to Construct was issued.

(3) An owner or operator of a Facility with an approved B-Cap may request a time extension for the dates specified in subparagraph (h)(8)(C) or (h)(8)(D) to meet the Facility BARCT Emission Targets in an approved I-Plan provided:

(A) The Permit to Construct was issued more than 18 months after the complete permit application was submitted for a Unit, provided:

(i) The permit application was submitted on or before the Permit Application Submittal Date specified in the approved I-Plan; and

(ii) The time extension request is no longer than the time difference between 18 months after the complete permit application was submitted and when the Permit to Construct was issued;

(B) A time extension is requested pursuant to paragraph (j)(1); or

(C) A time extension is requested pursuant to paragraph (j)(2).

(4) An owner or operator of a Facility shall submit a time extension request in writing to the Executive Officer:

(A) No later than 180 days prior to the compliance schedule in subparagraph (f)(1)(B) or the approved I-Plan, for a time extension request pursuant to paragraph (j)(1) or (j)(2); or

(B) No later than 180 days prior to the B-Cap Effective Date of the Facility BARCT Emission Target in Table 6, for a time extension request pursuant to paragraph (j)(3).

(5) An owner or operator of a facility that submits a time extension request pursuant to paragraph (j)(4) shall include:

(A) The phase and the Unit needing a time extension;

(B) The date the complete permit application was submitted;

(C) The date the Executive Officer issued the Permit to Construct;

(D) For a time extension request pursuant to paragraph (j)(3), specify the Unit BARCT B-Cap Annual Emissions;

(E) The additional time needed to complete the emission reduction project;

(F) Specify if the time extension request is for paragraph (j)(1), (j)(2), and/or (j)(3);

(G) Provide the month and year of the scheduled turnaround, and the subsequent turnaround, if applicable, for the Unit to qualify for time extension request pursuant to paragraph (j)(2); and

(H) The reason(s) a time extension is requested.

(6) The Executive Officer will review the request for the time extension and act on the request within 60 days of receipt provided an owner or operator of a Facility:

(A) Meets the requirements of paragraph (j)(1), (j)(2), or (j)(3), as applicable;

(B) Submitted the written request within the timeframe and includes the applicable information pursuant to paragraph (j)(4);

(C) For a time extension request pursuant to paragraph (j)(1), provides at a minimum:

(i) Information on schedules and/or construction plans documenting the key milestones and which key milestone(s) were delayed with an explanation of actions the owner or operator took to ensure milestones were met and why the delay necessitates additional time for delays due to missed milestones;

(ii) Information to substantiate that the information submitted to another agency was timely, including the date when the application was submitted, and documentation from the agency of reason for the delay for delays related to the other agency approvals;

(iii) Purchase orders, invoices, and communications from vendors that demonstrate that equipment was ordered in a timely fashion and delays are outside of the control of the owner or operator for delays related to the delivery of parts or equipment; and

(iv) An explanation of the service, when the service was requested, the response time, and information to substantiate why the delay necessitates additional time for delays related to contract workers, source testers, installers, or other services.

(D) Provides documentation to substantiate that one of the provisions under subparagraph (j)(2)(C) has been met if requesting a time extension request pursuant to paragraph (j)(2); and

(E) Provides documentation of the date the Permit to Construct was issued for each Unit, to substantiate that the Executive Officer issued the Permit to Construct more than 18 months after the date permit application was required to be submitted pursuant to an approved I-Plan if requesting a time extension request pursuant to paragraph (j)(3).

(7) The Executive Officer shall determine the duration of the time extension based the information provided in paragraph (j)(6) and shall be no longer than:

(A) 12 months for a time extension request pursuant to paragraph (j)(1) or subparagraph (j)(3)(B);

(B) The time necessary to meet the Alternative BARCT NOx Limit in the subsequent turnaround for a time extension request pursuant to paragraph (j)(2) or subparagraph (j)(3)(C); or

(C) The time between 18 months after the complete permit application was submitted and when the Permit to Construct was issued for the Unit applicable to the time extension pursuant to subparagraph (j)(3)(A).

(8) An owner or operator of a Facility that receives a request from the Executive Officer to provide additional information to substantiate the time extension request, shall provide the additional information within the timeframe specified by the Executive Officer. The Executive Officer will review the request for the time extension and act on the request within 60 days of the receipt of the additional information.

(9) An owner or operator of a Facility that receives an approval for a time extension that was requested pursuant to paragraphs (j)(1) or (j)(2), shall meet the applicable NOx and Corresponding CO Concentration Limits or the Alternative BARCT Concentration Limit within the timeframe in the approval of the time extension, where the approval represents an amendment to the I-Plan.

(10) An owner or operator of a Facility that receives an approval for a time extension that was requested pursuant to paragraph (j)(3), shall meet the adjusted Facility BARCT Emission Target where:

(A) The Facility BARCT Emission Target will be adjusted to add the Unit BARCT B-Cap Annual Emissions from the previous phase, or if complying with Phase I, the Baseline Unit Emissions for each Unit;

(B) The Facility BARCT Emission Target will be adjusted to remove the Unit BARCT B-Cap Annual Emissions based on the applicable phase for each Unit in the approved I-Plan;

(C) The adjustment of the Facility BARCT Emission Target pursuant to subparagraphs (j)(10)(A) and (j)(10)(B) shall be based on the duration of time determined by the Executive Officer and no longer than the duration of time specified under paragraph (j)(7), and shall be implemented on January 1 or July 1 of a calendar year; and

(D) The approval of a time extension request pursuant to paragraph (j)(3), represents an amendment to an approved I-Plan and B-Cap.

(11) If the Executive Officer notifies the owner or operator of a Facility of a disapproval of a time extension request, the owner or operator shall meet the NOx and CO concentration limits in Table 1, an approved B-Plan, or an approved B-Cap within 60 calendar days after receiving notification of disapproval of the time extension request or pursuant to the compliance schedule in paragraph (f)(1) or the schedule in an approved I-Plan.

(k) CEMS Requirements

(1) An owner or operator of a Former RECLAIM Facility with a Unit with a Rated Heat Input Capacity of greater than or equal to 40 MMBtu/hour shall install, certify, operate, and maintain a CEMS to measure NOx and O_2 emissions pursuant to the applicable Rule 218.2 and Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications requirements to demonstrate compliance with the applicable NOx and CO concentration limits.

(2) An owner or operator of a Facility with a Sulfuric Acid Furnace subject to the NOx and CO concentration limits in Table 1, Table 3, an approved B-Plan, or an approved B-Cap shall:

(A) Within 12 months from becoming a Former RECLAIM Facility, install, certify, operate, and maintain a CEMS to measure NOx emissions pursuant to the applicable Rules 218.2 and 218.3 requirements to demonstrate compliance with the applicable NOx and CO concentration limits; and

(B) Within 12 months from [*DATE OF ADOPTION*] install, certify, operate, and maintain a CEMS that complies with the Rules 218.2 and 218.3 requirements to measure O_2 and demonstrate compliance with the applicable NOx and CO concentration limits.

(3) An owner or operator of a Unit with a CEMS that measures CO at [*DATE OF ADOPTION*] must operate and maintain the CO CEMS pursuant to the applicable Rules 218.2 and 218.3 requirements to demonstrate compliance with the Corresponding CO Concentration Limits in Table 1, Table 2, or Table 3 and certify the CEMS within 12 months of [*DATE OF ADOPTION*] pursuant to the applicable Rules 218.2 and 218.3 requirements.

(4) An owner or operator of a Former RECLAIM Facility with a Unit with a certified CEMS shall exclude invalid CEMS data pursuant to Rules 218.2 and 218.3.

(5) Missing Data Procedures for a Facility Complying with a B-Cap

An owner or operator of a Facility with a Unit with an approved B-Cap with a certified CEMS that is not collecting data, shall:

(A) Calculate missing data using the average of the recorded emissions for the hour immediately before the missing data period and the hour immediately after the missing data period, if the missing data period is less than or equal to eight continuous hours; or

(B) Calculate missing data using the maximum hourly emissions recorded for the previous 30 days, commencing on the day immediately prior to the day the missing data occurred, if the missing data period is more than eight continuous hours.

(l) Source Test Requirements

(1) An owner or operator of a Facility with a Unit that is not required to install and operate a CEMS pursuant to subdivision (k) shall be required to conduct a source test with a duration of at least 60 minutes but no longer than 120 minutes and demonstrate compliance with the applicable NOx and CO concentration limits and ammonia South Coast AQMD permit limit (permit limit), if applicable, by conducting source tests pursuant to the source test schedule in:

(A) Table 7 – Source Testing Schedule for Units without Ammonia Emissions in the Exhaust (Table 7) for a Unit that does not vent to post-combustion air pollution control equipment with ammonia injection; or

(B) Table 8 – Source Testing Schedule for Units with Ammonia Emissions in the Exhaust (Table 8) for a Unit that vents to post-combustion air pollution control equipment with ammonia injection.

TABLE 7: SOURCE TESTING SCHEDULE
FOR UNITS WITHOUT AMMONIA EMISSIONS IN THE EXHAUST

CEMS Status	Source Test Schedule
Vapor Incinerators <40 MMBtu/hr and Flares	
Units Operating without NOx and CO CEMS	• Conduct simultaneous source tests for NOx and CO within 12 months of being subject to applicable NOx and CO concentration limits and every 36 months thereafter
Units Operating with NOx CEMS and without CO CEMS	• Conduct a source test for CO within 12 months of being subject to applicable NOx and CO concentration limits and every 36 months thereafter
Units Operating without a NOx CEMS and with a CO CEMS	• Conduct a source test for NOx within 12 months of being subject to applicable NOx and CO concentration limits and every 36 months thereafter
All Other Units	
Units Operating without NOx and CO CEMS	• Conduct simultaneous source tests for NOx and CO quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx and CO concentration limits • If an annual source test demonstrates an exceedance of applicable NOx or CO concentration limit, four consecutive quarterly source tests must demonstrate compliance with the applicable NOx and CO concentration limits prior to resuming annual source tests

CEMS Status	Source Test Schedule
Units Operating with NOx CEMS and without CO CEMS	• Conduct a source test for CO within 12 months of being subject to applicable NOx and CO concentration limits and annually thereafter
Units Operating without NOx CEMS and with CO CEMS	• Conduct a source test for NOx quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx concentration limit • If an annual source test demonstrates an exceedance of a NOx concentration limit, four consecutive quarterly source tests must demonstrate compliance with the NOx concentration limit prior to resuming annual source tests

TABLE 8: SOURCE TESTING SCHEDULE
FOR UNITS WITH AMMONIA EMISSIONS IN THE EXHAUST

CEMS Status	Source Test Schedule
Units Operating without NOx, CO, and Ammonia CEMS	• Conduct simultaneous source tests for NOx, CO, and ammonia quarterly during the first 12 months of being subject to applicable NOx concentration and CO concentration limit • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx and CO concentration limits, and ammonia permit limit • If an annual source test demonstrates an exceedance with the NOx concentration limit, CO concentration limit, or ammonia permit limit, four consecutive quarterly source tests must demonstrate compliance with the applicable NOx and CO concentration limits, and ammonia permit limit prior to resuming annual source tests
Units Operating with NOx CEMS and without CO and Ammonia CEMS	• Conduct simultaneous source tests for CO and ammonia quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits, if four consecutive quarterly source tests demonstrate compliance with the CO concentration limit and ammonia permit limit • If an annual source test demonstrates an exceedance with a CO concentration limit or ammonia permit limit, four consecutive quarterly source tests must demonstrate compliance with the CO concentration limit and ammonia permit limit prior to resuming annual source tests

CEMS Status	Source Test Schedule
Units Operating with NOx and CO CEMS and without Ammonia CEMS	• Conduct a source test for ammonia quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the ammonia permit limit • If an annual source test demonstrates an exceedance with the ammonia permit limit, four consecutive quarterly source tests must demonstrate compliance with the ammonia permit prior to resuming annual source tests
Units Operating with NOx and Ammonia CEMS and without CO CEMS	• Conduct a source test for CO within 12 months of being subject to applicable NOx and CO concentration limits and annually thereafter
Units Operating with Ammonia CEMS and without NOx and CO CEMS	• Conduct simultaneous source tests for NOx and CO quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx and CO concentration limits • If an annual source test demonstrates an exceedance of applicable NOx concentration limit or CO concentration limit, four consecutive quarterly source tests must demonstrate compliance with the NOx and CO concentration limits prior to resuming annual source tests

CEMS Status	Source Test Schedule
Units Operating with CO and Ammonia CEMS and without NOx CEMS	• Conduct a source test for NOx quarterly during the first 12 months of being subject to appliable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx concentration limit • If an annual source test demonstrates an exceedance with the NOx concentration limit, four consecutive quarterly source tests must demonstrate compliance with the applicable NOx concentration limit prior to resuming annual source tests
Units Operating with CO CEMS and without NOx and Ammonia CEMS	• Conduct simultaneous source tests for NOx and ammonia quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx concentration limit and ammonia permit limit • If an annual source test demonstrates an exceedance of applicable NOx concentration limit or ammonia permit limit, four consecutive quarterly source tests must demonstrate compliance with the NOx concentration and ammonia permit limit limits prior to resuming annual source tests

(2) An owner or operator of a Facility with a Unit that is required to conduct an annual source test pursuant to Table 7 or Table 8 shall:

(A) Conduct the source test every calendar year but no earlier than six calendar months after the previous source test; or

(B) Conduct a source test no later than 90 days after the date of resumed operation for a Unit that has not operated for at least six consecutive calendar months and maintain a record of monthly fuel usage using a non-resettable fuel meter to demonstrate that the Unit has not been operated for at least six consecutive calendar months.

(3) An owner or operator of a Facility with a Unit that elects to install and operate a CEMS to demonstrate compliance with an applicable NOx and CO concentration limits, or ammonia permit limit, shall meet the CEMS requirements under subdivision (k) in lieu of the source test requirements in subdivision (l).

(4) An owner or operator of a Facility with a new or modified Unit shall conduct the initial compliance demonstration:

(A) Through an initial source test conducted within six months from commencing operation for a Unit with an averaging time less than 120 minutes pursuant to paragraph (l)(1);

(B) With a certified CEMS for Units with an averaging time greater than 120 minutes pursuant to Table 1 or Table 2; or

(C) Through CEMS recertification pursuant to the applicable requirements in Rule 218.2 and Rule 218.3 for Units that are required to adjust the NOx span range.

(5) An owner or operator of a Facility with a Unit required to conduct a source test pursuant to this subdivision shall:

(A) Submit a complete source test protocol, that includes an averaging time duration of at least 60 minutes but no longer than 120 minutes, for approval at least 60 days prior to conducting the source test unless otherwise approved by the Executive Officer; and

(B) Conduct the source test within 90 days after a written approval of the source test protocol by the Executive Officer is distributed, unless otherwise approved by the Executive Officer.

(6) ~~At least one week prior to conducting a source test, a~~An owner or operator of a Facility required to conduct a source test shall:

(A) ~~n~~Notify the Executive Officer by calling 1-800-CUT-SMOG of the intent to conduct source testing for a Unit ~~and shall provide:~~ at least one week prior to conducting a source test; or

(B) Submit quarterly source test lists by the 15th of the first month of each calendar quarter to the Executive Officer that includes the units that are scheduled for source tests in the following calendar quarter and shall notify the Executive Officer in the event a source test previously reported on the quarterly source test list is rescheduled by calling 1-800-CUT-SMOG at least one week prior to conducting or cancelling a source test; and

(C) Include the following in the source test notification or quarterly source test list pursuant to subparagraphs (l)(6)(A) and (l)(6)(B):

(~~A~~i) Facility name and identification number;

(~~B~~ii) Device identification number; and

(~~C~~iii) Date when source test will be conducted.

(7) Unless requested by the Executive Officer, after the approval of the initial source test protocol pursuant to paragraph (l)(5), an owner or operator of a Facility is not required to resubmit a source test protocol for approval pursuant to paragraph (l)(5) if:

(A) The method of operation of the Unit has not been altered in a manner that requires a complete permit application submittal;

(B) Rule or South Coast AQMD permit concentration limits have not become more stringent since the previous source test;

(C) There have been no changes in the source test method(s) that is referenced in the approved source test protocol; and

(D) The approved source test protocol is representative of the operation and configuration of the Unit.

(8) An owner or operator of a Facility with a Unit shall conduct the source test using a South Coast AQMD approved contractor under the Laboratory Approval Program:

(A) Using a South Coast AQMD approved source test protocol;

(B) Using the applicable test methods:

(i) South Coast AQMD Source Test Method 100.1 – Instrumental Analyzer Procedures for Continuous Gaseous Emission Sampling;

(ii) South Coast AQMD Source Test Method 7.1 – Determination of Nitrogen Oxide Emissions from Stationary Sources and South Coast AQMD Source Test Method 10.1 – Carbon Monoxide and Carbon Dioxide by Gas Chromatograph/Non-Dispersive Infrared Detector (GC/NDIR) – Oxygen by Gas Chromatograph-Thermal Conductivity (GC/TCD);

(iii) South Coast AQMD Source Test Method 207.1 – Determination of Ammonia Emissions from Stationary Sources; or

(iv) Any other test method determined to be equivalent and approved by the Executive Officer, and either the California Air Resources Board or the U. S. Environmental Protection Agency, as applicable.

(C) During operation other than startup and shutdown; and

(D) During normal operating conditions.

(9) An owner or operator of a Facility with a Vapor Incinerator may elect to demonstrate that the Unit meets the applicable NOx concentration limit based on the NOx emission from only the burner, without the waste stream being directed to the Unit.

(10) An owner or operator of a Facility shall submit all source test reports, including the source test results and a description of the Unit tested, to the Executive Officer within 90 days of completion of the source test.

(11) Emissions determined to exceed any limits established by this rule by any of the reference test methods in subparagraph (l)(8)(B) shall constitute a violation of the rule.

(12) An owner or operator of a Facility with a Unit that exceeds the applicable limit established by this rule by any of the reference test methods in subparagraph (l)(8)(B) shall inform the Executive Officer within 72 hours from the time the owner or operator knew of excess emissions, or reasonably should have known.

(m) Diagnostic Emission Checks

(1) An owner or operator of a Facility with a Unit required to perform a source test every 36 months pursuant to subdivision (l) shall also:

(A) Perform 30-minute diagnostic emissions checks of NOx, CO, and O_2 emissions, with a portable NOx, CO, and O_2 analyzer that is calibrated, maintained and operated in accordance with manufacturers specifications and recommendations of the South Coast AQMD Combustion Gas Periodic Monitoring Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Combustion Sources Subject to Rules 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, 1146 –

Emissions of Oxides of Nitrogen From Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, and 1146.1 – Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters;

(B) Conduct the diagnostic emission checks by a person who has completed an appropriate training program approved by South Coast AQMD in the operation of portable analyzers and has received a certification issued by the South Coast AQMD; and

(C) Conduct the diagnostic test every 365 days or every 8,760 operating hours, whichever occurs earlier except this requirement may be extended for 365 days or 8,670 operating hours from the date of any source test conducted as required pursuant to Table 7.

(2) A diagnostic emissions check that finds the emissions in excess of those allowed by this rule or a South Coast AQMD permit condition shall not constitute a violation of this rule if an owner or operator of a Facility corrects the problem and demonstrates compliance with another diagnostic emissions check within 72 hours from the time the owner or operator knew of excess emissions, or reasonably should have known, or shut down the Unit by the end of an operating cycle, whichever is sooner. Any diagnostic emission check performed in accordance with subparagraph (m)(1)(A) conducted by South Coast AQMD staff that finds emissions in excess of those allowed by this rule or a South Coast AQMD permit condition shall be a violation.

(n) Monitoring, Recordkeeping, and Reporting Requirements

(1) Operating Log

An owner or operator of a Facility shall maintain the following daily records for each Unit, in a manner approved by the Executive Officer:

(A) Time and duration of startup and shutdown events;

(B) Total hours of operation;

(C) Quantity of fuel used; and

(D) Cumulative hours of operation to date for the calendar year.

(2) An owner or operator of a Facility that elects to meet the NOx concentration limits in an approved B-Cap pursuant to paragraph (g)(3) shall:

(A) Report the following to the Executive Officer by the 15th of each month:

(i) Beginning no later than January 1, 2024, the daily facility-wide NOx mass emissions by device, expressed in pounds per day, from the previous calendar month; and

(ii) Beginning no later than January 1, 2025, the daily facility-wide NOx mass emissions by device, expressed in pounds per day, based on a 365-day rolling NOx average from the previous 365 days.

(B) Maintain CEMS for all applicable Units operated with a certified CEMS to determine daily mass emissions for those Units;

(C) Use an enforceable method, approved by the Executive Officer, for all applicable Units operated without a certified CEMS to determine daily mass emissions based on a source test pursuant to subdivision (l) and fuel use as determined based on a non-resettable totalizing fuel meter, where the owner or operator of a Facility shall:

(i) Beginning January 1, 2024, install and operate a non-resettable totalizing fuel meter, unless a metering system is currently installed and the fuel meter is approved in writing by the Executive Officer;

(ii) Each non-resettable totalizing fuel meter required under subparagraph (n)(2)(C) that requires dependable electric power to operate shall be equipped with a permanent supply of electric power that cannot be unplugged, switched off, or reset except by the main power supply circuit for the building and associated equipment or the safety shut-off switch;

(iii) Ensure that the continuous electric power to the non-resettable totalizing fuel meter required under subparagraph (n)(2)(C) may only be shut off for maintenance or safety;

(iv) Ensure each non-resettable totalizing fuel meter required under subparagraph (n)(2)(C) is calibrated and recalibrate the meter annually, thereafter, based on the manufacturer's recommended procedures. If the non-resettable totalizing fuel meter was calibrated within one year prior to January 1, 2024, the next calibration shall be conducted within one year of the anniversary date of the prior calibration; and

(v) Monitor and maintain hours of operation records using a:

(A) Calibrated non-resettable totalizing time meter or equivalent method approved in writing by the Executive Officer for the hours per year validation; or

(B) Calibrated fuel meter or equivalent method approved in writing by the Executive Officer for the annual throughput limit equivalent to hours per year validation.

(D) Maintain daily records of mass emissions, in pounds per day, from all Units included in an approved B-Cap including:

(i) Emissions during start-ups, shutdowns, and maintenance;

(ii) CEMS data identified as invalid and justification;

(iii) Data substituted for missing data pursuant to paragraph (k)(5);

(E) Demonstrate compliance with the Facility BARCT Emission Target in the B-Cap on a daily basis from 365-day rolling average.

(3) An owner or operator of a Facility subject to the interim emission limit pursuant to paragraph (e)(2) shall maintain the following daily records for each Unit, in a manner approved by the Executive Officer:

(A) Actual daily mass emissions, in pounds, for all Boilers and Process Heaters with a Rated Heat Input Capacity of greater than or equal to 40 MMBtu/hour;

(B) Combined maximum Rated Heat Input Capacity for all Boilers and Process Heaters with a Rated Heat Input Capacity of greater than or equal to 40 MMBtu/hour; and

(C) Calculated interim NOx emission rate pursuant to Attachment A Section (A-2) of this rule.

(4) An owner or operator of a Facility shall keep and maintain the following records on-site for five years, except that all data gathered or computed for intervals of less than 15 minutes shall be maintained for a minimum of 48 hours, and shall make them available to the Executive Officer upon request:

(A) CEMS data;

(B) Source tests reports;

(C) Diagnostic emission checks; and

(D) Written logs of startups, shutdowns, and breakdowns, all maintenance, service and tuning records, and any other information required by this rule.

(5) An owner or operator of a Facility with a Boiler or Process Heater that is exempt from the applicable NOx Concentration Limits in Table 1 pursuant to paragraphs (o)(5) and (o)(6), or an owner or operator of a Facility with a Flare that is exempt from the applicable NOx Concentration Limits in Table 1 pursuant to subparagraph (o)(8)(A) shall:

(A) Within 90 days of [*DATE OF ADOPTION*], install and operate a non-resettable totalizing time meter or a fuel meter, unless a metering system is currently installed, and the fuel meter is approved in writing by the Executive Officer;

(B) Within 90 days of [*DATE OF ADOPTION*], each non-resettable totalizing time meter or a fuel meter required under subparagraph (n)(5)(A) that requires dependable electric power to operate shall be equipped with a permanent supply of electric power that cannot be unplugged, switched off, or reset except by the main power supply circuit for the building and associated equipment or the safety shut-off switch;

(C) Ensure that the continuous electric power to the non-resettable totalizing time meter or fuel meter required under subparagraph (n)(5)(A) may only be shut off for maintenance or safety;

(D) Within 90 days of [*DATE OF ADOPTION*], ensure that each non-resettable totalizing time meter or fuel meter is calibrated and recalibrate the meter annually, thereafter, based on the manufacturer's recommended procedures. If the non-resettable totalizing time meter or fuel meter was calibrated within one year prior to [*DATE OF ADOPTION*], the next calibration shall be conducted within one year of anniversary date of the prior calibration; and

(E) Monitor and maintain hours of operation records using a:

(i) Calibrated non-resettable totalizing time meter or equivalent method approved in writing by the Executive Officer for the hours per year validation; or

(ii) Calibrated fuel meter or equivalent method approved in writing by the Executive Officer for the annual throughput limit equivalent to hours per year validation.

(6) An owner or operator of a Facility with a Vapor Incinerator that is exempt from the applicable NOx Concentration Limits in Table 1 pursuant to paragraph (o)(9) shall record:

(A) The annual throughput using a calibrated fuel meter or equivalent method approved in writing by the Executive Officer; and

(B) Emissions using a source test pursuant to subdivision (l) or by using a default emission factor approved in writing by the Executive Officer.

(7) An owner or operator of a Facility with a Unit subject to the compliance schedule in subparagraphs (f)(2)(B) and (f)(2)(C) shall maintain records of burner replacement, including number of burners and date of installation.

(8) An owner or operator of a Facility with a Unit subject to the compliance schedule in subparagraph (f)(4)(A) shall maintain records of the date the existing post-combustion air pollution control equipment was installed or replaced.

(9) An owner or operator of a Facility with a Gas Turbine complying with the NOx concentration limit pursuant to paragraph (d)(4) shall:

(A) Maintain a daily operating record that includes the actual start and stop time, total hours of operation, and type (liquid or gas) and quantity of the fuel used;

(B) Maintain the operating records for at least five years from the initial date the Gas Turbine complied with the concentration limit pursuant to paragraph (d)(4); and

(C) Make the operating records available to the Executive Officer upon request.

(10) An owner or operator of a Former RECLAIM Facility shall submit a list of Boilers and Process Heaters, within 60 days of becoming a Former

RECLAIM Facility, identified by device identification number with a description of each Unit, to the Executive Officer identifying which Units will meet the NOx and Corresponding CO Concentration Limits in Table 3 and which Units will meet the interim NOx emission limit pursuant to paragraph (e)(2).

(o) Exemptions

(1) Boilers or Process Heater 2 MMBtu/hour or less

The provisions of this rule shall not apply to an owner or operator of a Facility with a Boiler or Process Heater with a Rated Heat Input Capacity of 2 MMBtu/hour or less that are fired with liquid and/or gaseous fuel and used exclusively for space or water heating and are subject to Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters.

(2) Low-Use Boilers with a Rated Heat Input Capacity of less than 40 MMBtu/hour

An owner or operator of a Facility with a Boiler with a Rated Heat Input Capacity of less than 40 MMBtu/hour that operates 200 hours or less per calendar year, or with an annual throughput limit equivalent to 200 hours per calendar year, shall be exempt from the requirements in:

(A) Subdivision (d) provided:

(i) The Boiler has an enforceable South Coast AQMD permit conditions that limits the operating hours to 200 hours or the annual throughput equivalent to 200 hours; and

(ii) The Boiler operates in compliance with the permit conditions pursuant to clause (o)(2)(A)(i).

(B) Subdivisions (k), (l), and (m) provided the Unit is not included in an approved B-Plan or an approved B-Cap.

(3) Low-Use Boiler or Process Heater with a Rated Heat Input Capacity of greater than or equal to 40 MMBtu/hour

An owner or operator of a Facility with a Boilers or Process Heater with a Rated Heat Input Capacity of greater than or equal to 40 MMBtu/hour that is fired at less than 15 percent of the maximum Rated Heat Input Capacity per calendar year, shall be exempt from the applicable NOx and CO concentration limits in Table 1, Table 2, or an approved B-Plan provided:

(A) The Boiler or Process Heater has a South Coast AQMD permit that specifies a condition that limits the Boiler or Process Heater to being fired at less than 15 percent of the maximum Rated Heat Input Capacity per calendar year; and

(B) The Boiler or Process Heater operates in compliance with the permit condition pursuant to subparagraph (o)(3)(A).

(4) An owner or operator of a Facility with a FCCU that must bypass the post-combustion air pollution control equipment to conduct Boiler inspections required under California Code of Regulations, Title 8, Section 770(b) shall be exempt from the applicable NOx and CO concentration limits during the required Boiler inspections.

(5) FCCU Startup Boilers and Process Heaters

An owner or operator of a Facility with a Boiler or Process Heater which is used only for startup of an FCCU and that Boiler or Process Heater is operated for 250 hours or less per calendar year shall be exempt from the requirements in:

(A) Subdivisions (d) provided:

(i) The Boiler or Process Heater has a South Coast AQMD permit that specifies conditions that limits the operating hours at or less than 250 hours per calendar year; and

(ii) The Boiler or Process Heater operates in compliance with the permit condition pursuant to clause (o)(5)(A)(i).

(B) Subdivisions (k), (l) and (m) provided the Unit is not included in an approved B-Plan or an approved B-Cap.

(6) Startup or Shutdown Boilers and Process Heaters at Sulfuric Acid Plants

An owner or operator of a Facility with a Process Heater used for startup or a Boiler used during startup or shutdown at a Sulfuric Acid Plant that does not exceed 90,000 MMBtu of annual Heat Input per calendar year shall be exempt from the requirements in:

(A) Subdivision (d) provided:

(i) The Boiler or Process Heater has a South Coast AQMD permit that specifies conditions that limits the Heat Input to 90,000 MMBtu or lower per calendar year; and

(ii) The Process Heater or Boiler operates in compliance with the South Coast AQMD permit condition pursuant to clause (o)(6)(A)(i).

(B) Subdivisions (k), (l), and (m) provided the Unit is not included in an approved B-Plan or an approved B-Cap.

(7) Boiler or Process Heater Operating Only the Pilot

An owner or operator of a Facility with a Boiler or Process Heater operating only the pilot prior to startup or after shutdown shall be exempt from the ~~concentration limits in paragraph (d)(2), Table 1, Table 2, Table 3, an approved B-Plan, or an approved B-Cap~~ NOx and Corresponding CO Concentration Limits and the Alternative BARCT NOx Limits and may exclude those emission from the rolling average calculation pursuant to Attachment A of this rule.

(8) Flares

(A) An owner or operator of a Facility with a Flare that emits less than or equal to 550 pounds of NOx per calendar year shall be exempt from the requirements in subdivisions (d), (e), and (l), provided:

(i) The Flare has enforceable South Coast AQMD permit conditions that limits the emissions not to exceed 550 pounds of NOx per year; and

(ii) The Flare is in compliance with the permit condition pursuant to clause (o)(8)(A)(i).

(B) An owner or operator of a Facility with an open Flare, which is an unshrouded Flare, shall not be required to conduct source testing pursuant to subdivision (l).

(9) Vapor Incinerators

An owner or operator of a Facility with a Vapor Incinerator with a Rated Heat Input Capacity of 2 MMBtu/hour or less that emits:

(A) Less than 100 pounds of NOx per calendar year shall be exempt from the requirements in subdivisions (d), (e), and (l) provided the Vapor Incinerator:

(i) Has enforceable South Coast AQMD permit conditions that limit NOx emissions to less than 100 pounds of NOx per calendar year through operating hours or annual throughput; and

(ii) Operates in compliance with the permit condition pursuant to clause (o)(9)(A)(i).

(B) Less than 1,000 pounds but more than 100 pounds of NOx per calendar year shall be exempt from the requirements in subdivision (d) until the Unit is replaced or [*TEN YEARS AFTER DATE OF ADOPTION*], whichever is sooner, provided the Vapor Incinerator:

(i) Has enforceable South Coast AQMD permit conditions that limit NOx emissions to less than 1,000 pounds of NOx per calendar year through operating hours or annual throughput; and

(ii) Operates in compliance with the permit condition pursuant to clause (o)(9)(B)(i).

ATTACHMENT A

SUPPLEMENTAL CALCULATIONS

(A-1) Rolling Average Calculation for Emission Data Averaging

$$C_{Avg} = \sum_{i=t}^{t+N-1} C_i \Big/ N$$

Where:

C_{Avg} = The average emission concentration at time t

t = Time of average concentration (hours)

C_i = The measured or calculated concentration for a Unit with a CEMS at the i^{th} subset of data; one-hour for a Unit with an averaging time of 24 hours or less and 24-hour for a Unit with an averaging time of greater than 24 hours[1]

N = Averaging time (hours).

[1] As calculated pursuant to South Coast AQMD Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications.

(A-2) Interim NOx Emission Rate Calculation

An owner of operator shall calculate interim NOx emission rates the mass emissions from the prior 365 days where emissions for 364 days will be based on emissions while the facility was in RECLAIM and emissions for the 365th day will be based on the day the facility became a former RECLAIM facility, as follows:

(A-2.1) Hourly Mass Emissions (pounds/hour)

Sum the actual annual mass emissions of all Boilers and Process Heaters with a Rated Heat Input Capacity of greater than or equal to 40 MMBtu/hour and any Boilers and Process Heaters with a Rated Heat Input Capacity of less than 40 MMBtu/hour that operate a certified CEMS, and divide by 8,760 hours for pounds per hour.

(A-2.2) Combined Maximum Rated Heat Input Capacity (MMBtu/hour)

Sum the combined maximum Rated Heat Input Capacity for all Boilers and Process Heaters with a Rated Heat Input Capacity of greater than or equal to 40 MMBtu/hour and any Boilers and Process Heaters with a Rated Heat Input Capacity of less than 40 MMBtu/hour that operate a certified CEMS.

(A-2.3) Interim Facility Wide NOx Emission Rate (pounds/MMBtu)

Divide the Hourly Mass Emissions in Section (A-2.1) by the combined Maximum Heat Input in Section (A-2.2) to determine the interim NOx emission rate.

ATTACHMENT B

CALCULATION METHODOLOGY FOR THE I-PLAN, B-PLAN, AND B-CAP

The purpose of this attachment is to provide details regarding how key elements of the I-Plan, B-Plan, and B-Cap are calculated. Key calculations provided in this attachment include: Baseline Unit Emissions and Baseline Facility Emissions; Final Phase Facility BARCT Emission Target; Total Facility NOx Emission Reductions; Phase I, Phase II, or Phase III Facility BARCT Emission Target; Phase I, Phase II or Phase III BARCT Equivalent Mass Emissions for a B-Plan; and Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions for a B-Cap.

(B-1) Baseline Unit Emissions and Baseline Facility Emissions

Baseline Unit Emissions shall be determined by the Executive Officer based on the applicable 2017 NOx Annual Emissions Reporting data, or another representative year, as approved by the Executive Officer, expressed in pounds per year. Baseline Facility Emissions are the sum of all the Baseline Unit Emissions subject to this rule and shall not include Baseline Unit Emissions for Units that are not operational on and after [*DATE OF ADOPTION*].

(B-2) Final Phase Facility BARCT Emission Target

The Final Phase Facility BARCT Emission Target is the Phase II Facility BARCT Emission Target for an I-Plan option with two phases or the Phase III Facility BARCT Emission Target for an I-Plan option with three phases. The Final Phase Facility BARCT Emission Target is used to establish the Phase II or Phase III BARCT Emission Target for a B-Cap. To establish the Final Phase Facility BARCT Emission Target, the owner or operator of a Facility must select if the basis of the emission target for each Unit will be based on NOx Concentration Limits in Table 1 or Table 2. The owner or operator of a Facility shall only select conditional NOx Concentration Limits in Table 2 if the requirements of subparagraphs (d)(2)(A) and (d)(2)(B) for the conditional NOx Concentration Limits are met or if the Unit is identified in Attachment D. For all other Units, the owner or operator of a Facility shall use NOx Concentration Limits in Table 1 as the basis of the Facility BARCT Emission Targets. To calculate the Final Phase Facility BARCT Emission Target for B-Cap, the owner or operator of a Facility shall use the NOx Concentration Limit in Table 1 for the Units that will be decommissioned.

(B-2.1) The Final Phase Facility BARCT Emission Target for a Facility complying with NOx concentration limits in Table 1, Table 2, an approved B-Plan or an approved B-Cap shall be calculated using the following equation:

$$\text{Final Phase Facility BARCT Emission Target} = \sum_{i=1}^{N}\left(\frac{C_{\text{Table 1 or Table 2}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions}\right)_i$$

Where:

N	=	Number of included Units in B-Plan or B-Cap
$C_{\text{Table 1 or Table 2}}$	=	The applicable NOx Concentration Limit in Table 1 or Table 2 for each Unit i included in B-Plan or B-Cap
C_{Baseline}	=	Representative NOx Concentration as defined in subdivision (c) for Unit i included in B-Plan or B-Cap
Baseline Unit Emissions	=	Baseline Unit Emissions for Unit i as defined in subdivision (c) and included in the I-Plan, B-Plan or B-C-ap as determined pursuant to section (B-1).

(B-3) Calculating Total Facility NOx Emission Reductions

Total Facility NOx Emission Reductions is the total reduction in NOx mass emissions per Facility or Facilities With The Same Ownership that would have been achieved if all Units met the NOx Concentration Limits in Table 1 or Table 2 of this rule based on the Baseline Facility Emissions.

(B-3.1) For a Facility complying with NOx concentration limits in Table 1 or Table 2, or an approved B-Plan, the Total NOx Emission Reductions is the difference between Baseline Facility Emissions and the Final Phase Facility BARCT Emission Target.

$$\text{Total Facility NOx Emission Reductions} = \text{Baseline Facility Emissions} - \text{Final Phase Facility BARCT Emission Target}$$

(B-3.2) For a Facility complying with NOx concentration limits in an approved B-Cap, the Total NOx Emission Reductions is the difference between Baseline Facility Emissions and the Final Phase Facility BARCT Emission Target with an additional 10 percent reduction.

$$\text{Total Facility NOx Emission Reductions}_{\text{B-Cap}} = \text{Baseline Facility Emissions} - (\text{Final Phase Facility BARCT Emission Target} \times 0.9)$$

(B-4) Calculating Phase I, Phase II, or Phase III Facility BARCT Emission Target

The Phase I, Phase II, or Phase III Facility BARCT Emission Target is the total NOx mass emissions per Facility based on the Total Facility NOx Emission Reductions and the Percent Reduction Target of Phase I, Phase II or Phase III of an I-Plan option in Table 6.

(B-4.1) For a Facility complying with NOx concentration limits in Table 1 or Table 2, or an approved B-Plan, the Phase I Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Facility Emissions and applying the selected I-Plan Phase I Percent Reduction Target from Table 6 to the Total NOx Emission Reductions.

$$\text{Phase I Facility BARCT Emission Target} = \text{Baseline Facility Emissions} - (\text{Phase I Percent Reduction Target} \times \text{Total Facility NOx Emission Reductions})$$

(B-4.2) For a Facility complying with NOx concentration limits in Table 1 or Table 2, or an approved B-Plan, if Phase II is not the final phase, Phase II Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Emissions and applying the selected I-Plan Phase II Percent Reduction Target from Table 6 to the Total NOx Emission Reductions.

$$\text{Phase II Facility BARCT Emission Target} \\ = \text{Baseline Facility Emissions} \\ - (\text{Phase II Percent Reduction Target} \\ \times \text{Total Facility NOx Emission Reductions})$$

(B-4.3) For a Facility complying with NOx concentration limits in Table 1 or Table 2, or an approved B-Plan, the final phase, Phase II for the two phase I-Plan or Phase III for the three phase I-Plan, the Phase II or Phase III Final Facility BARCT is the Final Phase Facility BARCT Target as calculated in Section B-2.1.

$$\text{Phase II or Phase III Facility BARCT Emission Target} \\ = \text{Final Phase Facility BARCT Emission Target}$$

(B-4.4) For a Facility complying with NOx concentration limits in an approved B-Cap, the Phase I, Phase II, and if applicable Phase III Facility BARCT Emission Target will be adjusted to the Baseline Unit Emissions in Phase I and to the Unit BARCT B-Cap Annual Emissions from the previous phase in Phase II and Phase III for each Unit with an approved time extension pursuant to sections (B-4.4.1), (B-4.4.2) and (B-4.4.3), where N is the total number of Units for which the time extension is approved, and M is the total number of Units for which the approved time extension is up.

(B-4.4.1) For a Facility complying with NOx concentration limits in an approved B-Cap with an approved time extension, the Phase I Facility BARCT Emission Target will be adjusted using the following equation:

$$\begin{aligned}
&\text{Phase I Facility BARCT Emission Target}_{\text{B-Cap}} \\
&= \text{Baseline Emissions} \\
&- \big(\text{Phase I Percent Reduction Target} \\
&\times \text{Total Facility NOx Emission Reductions}_{\text{B-Cap}}\big) \\
&+ \sum_{i=1}^{N} (\text{Baseline Unit Emissions}_i \\
&- \text{Phase I Unit BARCT B-Cap Annual Emissions}_i) \\
&- \sum_{j=1}^{M} \big(\text{Baseline Unit Emissions}_j \\
&- \text{Phase I Unit BARCT B-Cap Annual Emissions}_j\big)
\end{aligned}$$

(B-4.4.2) For a Facility complying with NOx concentration limits in an approved B-Cap with an approved time extension, the Phase II Facility BARCT Emission Target will be adjusted using the following equation:

$$\begin{aligned}
&\text{Phase II Facility BARCT Emission Target}_{\text{B-Cap}} \\
&= \text{Baseline Emissions} \\
&- \big(\text{Phase II Percent Reduction Target} \\
&\times \text{Total Facility NOx Emission Reductions}_{\text{B-Cap}}\big) \\
&+ \sum_{i=1}^{N} (\text{Phase I Unit BARCT B-Cap Annual Emissions}_i \\
&- \text{Phase II Unit BARCT B-Cap Annual Emissions}_i) \\
&- \sum_{j=1}^{M} \big(\text{Phase I Unit BARCT B-Cap Annual Emissions}_j \\
&- \text{Phase II Unit BARCT B-Cap Annual Emissions}_j\big)
\end{aligned}$$

(B-4.4.3) For a Facility complying with NOx concentration limits in an approved B-Cap with an approved time extension, the

Phase III Facility BARCT Emission Target will be adjusted using the following equation:

$$
\begin{aligned}
&\text{Phase III Facility BARCT Emission Target}_{\text{B-Cap}} \\
&= \text{Baseline Emissions} \\
&- \big(\text{Phase III Percent Reduction Target} \\
&\times \text{Total Facility NOx Emission Reductions}_{\text{B-Cap}}\big) \\
&+ \sum_{i=1}^{N} (\text{Phase II Unit BARCT B-Cap Annual Emissions}_i \\
&- \text{Phase III Unit BARCT B-Cap Annual Emissions}_i) \\
&- \sum_{j=1}^{M} \big(\text{Phase II Unit BARCT B-Cap Annual Emissions}_j \\
&- \text{Phase III Unit BARCT B-Cap Annual Emissions}_j\big)
\end{aligned}
$$

(B-5) Calculating Phase I, Phase II, and Phase III Mass Emissions for a Facility complying with Table 1 or Table 2 using an I-Plan

The Phase I, Phase II, or Phase III Mass Emissions is the total remaining NOx mass emissions per Facility based on the NOx Concentration Limits in Table 1 or Table 2 to meet Phase I, Phase II, or Phase III target reductions in an I-Plan. The Phase I, Phase II, and if applicable Phase III Mass Emissions incorporate the BARCT NOx Limit for each of the Units included in different phases of the I-Plan. The BARCT NOx Limits are the Unit specific NOx Concentration Limits that are specified in Table 1 or Table 2 to achieve the Facility BARCT Emission Targets.

(B-5.1) For a Facility complying with Table 1 or Table 2, the Phase I Mass Emissions for all Units complying with Table 1 or Table 2 shall be calculated using the following equation:

$$
\begin{aligned}
&\text{Phase I Mass Emissions}_{\text{Table 1/Table 2}} \\
&= \sum_{i=1}^{N} \left(\frac{C_{\text{Phase I BARCT NOx Limit}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions} \right)_i
\end{aligned}
$$

Where:

N	=	Number of Units complying with Table 1 or Table 2 under Phase I
$C_{\text{Phase I BARCT NOx Limit}}$	=	The applicable BARCT NOx Limit in Table 1 or Table 2 for Unit i complying with Table 1 or Table 2
C_{Baseline}	=	Representative NOx Concentration as defined in subdivision (c) for Unit i complying with Table 1 or Table 2
Baseline Unit Emissions	=	Baseline Unit Emissions for Unit i as defined in subdivision (c) and complying with Table 1 or Table 2.

(B-5.2) For a Facility complying with Table 1 or Table 2, the Phase II and if applicable, Phase III Mass Emissions for each Unit meeting a NOx Concentration Limit in Table 1 or Table 2 shall be calculated using the equation for Section B-5.1, with the use of the BARCT NOx Limit for that Unit included in Phase II or Phase III, if applicable.

(B-6) Calculating Phase I, Phase II, and Phase III BARCT Equivalent Mass Emissions for a B-Plan and B-Cap

The Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions is the total remaining NOx mass emissions per Facility to meet Phase I, Phase II, or Phase III target reductions in an I-Plan. The Phase I, Phase II, and if applicable Phase III BARCT Equivalent Mass Emissions incorporate the Alternative BARCT NOx Limit or Representative NOx Concentration for each of the Units included in different phases of the I-Plan. The Alternative BARCT NOx Limits are the Unit specific NOx concentration limits that are selected by the owner or operator of a Facility in the B-Plan or B-Cap to achieve the Facility BARCT Emission Targets in the aggregate, where the NOx and CO concentration limits will include the corresponding percent O_2 correction based on the averaging time pursuant to Table 1 or paragraph (l)(1), whichever is applicable. For any Unit where the Alternative BARCT NOx Limit is not specified, the Representative NOx Concentration should be used. For the B-Plan, decommissioned Units shall be removed from the Baseline Facility Emissions and the Facility BARCT Emission Targets. For the B-Cap, the emission reductions from decommissioned Units shall be incorporated in BARCT Equivalent Mass Emissions for the corresponding I-Plan phase pursuant to sections (B-6.3).

(B-6.1) For a B-Plan, the Phase I and Phase II (Phase II only for a three Phase B-Cap) BARCT Equivalent Mass Emissions for all Units included in a B-Plan shall be calculated using the following equation:

$$\text{Phase I and Phase II BARCT Equivalent Mass Emissions}_{\text{B-Plan}} = \sum_{i=1}^{N} \left(\frac{C_{\text{Phase I Alternative BARCT NOx Limit}} \; \boldsymbol{OR} \; C_{\text{Baseline}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions} \right)_i$$

Where:

N	=	Number of included Units in B-Plan under Phase I
$C_{\text{Phase I Alternative BARCT NOx Limit}}$	=	The applicable Alternative BARCT NOx Limit in an approved B-Plan for Unit i included in the B-Plan
C_{Baseline}	=	Representative NOx Concentration as defined in subdivision (c) for Unit i included in the B-Plan
Baseline Unit Emissions	=	Baseline Unit Emissions for Unit i as defined in subdivision (c) and included in the B-Plan.

(B-6.2) For a B-Plan, the Final Phase BARCT Equivalent Mass Emissions for all Unit included in a B-Plan shall be calculated using the following equation:

$$\text{Final Phase BARCT Equivalent Mass Emissions}_{\text{B-Plan}} = \sum_{i=1}^{N}\left(\frac{C_{\text{Phase I Alternative BARCT NOx Limit}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions}\right)_i$$

Where:

N = Number of included Units in B-Pl-an under Phase I

$C_{\text{Phase I Alternative BARCT NOx Limit}}$ = The applicable Alternative BARCT NOx Limit in an approved B-Pl-an for Unit i included in the B-Plan

C_{Baseline} = Representative NOx Concentration as defined in subdivision (c) for Unit i included in the B-Plan

Baseline Unit Emissions = Baseline Unit Emissions for Unit i as defined in subdivision (c) and included in the B-Plan.

(B-6.3) For a B-Cap, the Phase I and Phase II (Phase II only for a three Phase B-Cap) BARCT Equivalent Mass Emissions for all Units included in a B-Cap shall be calculated using the following equation:

$$\text{Phase I and Phase II BARCT Equivalent Mass Emissions}_{\text{B-Cap}} = \sum_{i=1}^{N}\left[\left(\frac{C_{\text{Phase I Alternative BARCT NOx Limit}}\ \boldsymbol{OR}\ C_{\text{Baseline}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions}\right)_i + (0_{\text{Decommissioned Units}})_i\right]$$

Where:

N = Number of included Units in B-Cap under Phase I

$C_{\text{Phase I Alternative BARCT NOx Limit}}$ =

The applicable Alternative BARCT NOx Limit in an approved B-Plan for Unit i included in the B-Cap

$C_{Baseline}$ = Representative NOx Concentration as defined in subdivision (c) for Unit i included in the B-Cap

Baseline Unit Emissions = Baseline Unit Emissions for Unit i as defined in subdivision (c) and included in the B-Cap.

(B-6.4) For a B-Cap, the Final Phase Equivalent Mass Emissions for all Unit included in a B-Cap shall be calculated using the following equation:

$$\text{Final Phase BARCT Equivalent Mass Emissions}_{B-Cap} = \sum_{i=1}^{N}\left[\left(\frac{C_{\text{Phase I Alternative BARCT NOx Limit}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions}\right)_i + (0_{\text{Decommissioned Units}})_i\right]$$

Where:

N = Number of included Units in B-Cap under Phase I

$C_{\text{Phase I Alternative BARCT NOx Limit}}$ = The applicable Alternative BARCT NOx Limit in an approved B-Plan for Unit i included in the B-Cap

$C_{Baseline}$ = Representative NOx Concentration as defined in subdivision (c) for Unit i included in the B-Cap

Baseline Unit Emissions = Baseline Unit Emissions for Unit i as defined in subdivision (c) and included in the B-Cap.

(B-7) Calculating Phase I, Phase II, and Phase III BARCT B-Cap Annual Emissions for a B-Cap

The Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions is the total remaining NOx mass emissions per Facility that incorporates emission reduction strategies. The Phase I, Phase II, and Phase III BARCT B-Cap Annual Emissions must be at or below the respective Phase I, Phase II, or Phase III Facility BARCT Emission Targets an I-Plan. Under the B-Cap, there are four emission reduction strategies that can be used to meet the Facility BARCT Emission Targets: Establishing an Alternative BARCT NOx Limit for each Unit included in Phase I, Phase II, or Phase III, decommissioning Units, Replacing Units, and Reducing Throughput for Units. The Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions calculation for the B-Cap acknowledges the four emission reduction strategies for each phase of the I-Plan. The Alternative BARCT NOx Limits are the Unit specific NOx concentration limits that are selected by the owner or operator of a Facility in the B-Cap to achieve the Final Phase Facility BARCT Emission Target in the aggregate. For any Unit where the Alternative BARCT NOx Limit is not specified, the Representative NOx Concentration should be used. The emission reductions from Decommission Units shall be incorporated in B-Cap pursuant to sections (B-7.1) and (B-8). Other types of reductions in mass emissions to demonstrate that the BARCT B-Cap Annual Emissions achieves the Total Facility NOx Emission Reductions for a B-Cap include emission reductions from reduced throughput, efficiency, reduced capacity, and any other strategy to reduce mass emissions.

(B-7.1) The Phase I and Phase II (Phase II only for a three Phase B-Cap) BARCT B-Cap Annual Emissions for all Unit included in a B-Cap shall be calculated using the following equation

$$\text{Phase I and Phase II BARCT B-Cap Annual Emissions} = \sum_{i=1}^{N}\left[\left(\frac{C_{\text{Phase I Alternative BARCT NOx Limit}}\ \boldsymbol{OR}\ C_{\text{Baseline}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions}\right)_i + \left(0_{\text{Decommissioned Units}}\right)_i - \left(\text{Throughput or Other Reductions}\right)_i\right]$$

Where:

N = Number of included Units in B-Cap under Phase I

$C_{\text{Phase I Alternative BARCT NOx Limit}}$ =

The applicable Alternative BARCT NOx Limit in an approved B-Cap for Unit i included in the B-Cap

C_{Baseline} = Representative NOx Concentration as defined in subdivision (c) for Unit i included in the B-Cap

$\text{Baseline Unit Emissions}$ = Baseline Unit Emissions as defined in subdivision (c) and for Unit i included in the B-Cap

$\text{Throughput or Other Reductions}$ = Emission reductions occurred from other than reducing the concentration limit.

(B-7.2) The Final Phase BARCT B-Cap Annual Emissions for all Unit included in a B-Cap shall be calculated using the following equation:

$$\text{Final Phase BARCT B} - \text{Cap Annual Emissions} = \sum_{i=1}^{N}\left[\left(\frac{C_{\text{Phase I Alternative BARCT NOx Limit}}}{C_{\text{Baseline}}} \times \text{ Baseline Unit Emissions}\right)_i + (0_{\text{Decommissioned Units}})_i - (\text{Throughput or Other Reductions})_i\right]$$

Where:

N = Number of included Units in B-Cap under Phase I

$C_{\text{Phase I Alternative BARCT NOx Limit}}$ = The applicable Alternative BARCT NOx Limit in an approved B-Cap for Unit i included in the B-Cap

C_{Baseline} = Representative NOx Concentration as defined in subdivision (c) for Unit i included in the B-Cap

Baseline Unit Emissions = Baseline Unit Emissions as defined in subdivision (c) and for Unit i included in the B-Cap

Throughput or Other Reductions = Emission reductions occurred from other than reducing the concentration limit.

(B-8) Emissions Reductions from Decommissioned Unit

For a B-Cap, emission reductions from decommissioned Units can be used to meet a Phase I, Phase II, or Phase III Facility BARCT Emission Target. The amount of emission reductions from a decommissioned Unit shall be determined using the equation below.

$$\text{Emission Reductions from Decommissioned Units} = \sum_{i=1}^{N}\left(\frac{C_{\text{Table 1}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions}\right)_i$$

Where:

N	=	Number of decommissioned Units in B-Cap
$C_{\text{Table 1}}$	=	The applicable NOx Concentration Limit in Table 1 for Unit i included in an approved B-C-ap
C_{Baseline}	=	Representative NOx Concentration as defined in subdivision (c) for Unit i included in an approved B-Cap
Baseline Unit Emissions	=	Baseline Unit Emissions for Unit i as defined in subdivision (c) and included in an approved B-Cap.

(B-9) Unit Reductions for conditional NOx and Corresponding CO Concentration Limits in Table 2

An owner or operator of a Facility with a Unit in a B-Plan or B-Cap that is demonstrating that the Unit Reduction is less than the thresholds pursuant to

~~clause (d)(3)(A)(ii) or (d)(3)(A)(iii)~~ subparagraph (d)(3)(B) or (d)(3)(C) shall calculate the Unit Reduction using the following equation:

$$\text{Unit Reduction} = \left(1 - \frac{C_{\text{Table 1}}}{C_{\text{Baseline}}}\right) \times \text{Baseline Unit Emissions}$$

Where:

$C_{\text{Table 1}}$	=	The applicable NOx Concentration Limit in Table 1 the Unit
C_{Baseline}	=	Representative NOx Concentration for the Unit
Baseline Unit Emissions	=	Baseline Unit Emissions.

ATTACHMENT C

FACILITIES EMISSIONS BASELINE

(C-1) Baseline Facility Emissions Table C-1 provides the Baseline Mass Emissions for Facilities with six or more Units subject to this rule. Baseline Facility Emissions in Table C-1 are based on 2017 reported emissions for Rule 1109.1 Units. A year other than 2017 was used for Units where the 2017 reported emissions were not representative of normal operations. Note: Table C-1 contains the emissions for all units at the Facilities with six or more Units, Facilities complying with an approved B-Plan or B-Cap may elect to exclude Boilers and Heaters <40 MMBtu/hour (e.g., Optional Units).

TABLE C-1: Baseline Mass Emissions for Facilities with Six or More Units

Facility	Facility ID	Baseline Facility Emissions (2017 or Representative Year) (tons/year)
AltAir Paramount, LLC	187165	24
Chevron Products Co.	800030	705
Lunday-Thagard Co. DBA World Oil Refining	800080	26
Phillips 66 Company/Los Angeles Refinery	171109	387
Phillips 66 Co/LA Refinery Wilmington PL	171107	456
Tesoro Refining and Marketing Co., LLC – Carson	174655	~~647~~639
Tesoro Refining and Marketing Co., LLC – Wilmington	800436	597
Tesoro Refining and Marketing Co., LLC – Sulfur Recovery Plant	151798	43
Tesoro Refining and Marketing Co., LLC, Calciner	174591	261
Torrance Refining Company LLC	181667	737
Ultramar Inc.	800026	249
Valero Wilmington Asphalt Plant	800393	4.8

ATTACHMENT D

UNITS THAT QUALIFY FOR CONDITIONAL LIMITS IN B-PLAN AND B-CAP

TABLE D-1: Boilers and Process Heaters >40 MMBtu/hr That Qualify for Conditional Limits in B-Plan or B-Cap using I-Plan Option 3

Facility ID	Device ID	Size (MMBtu/hr)
171109	D429	352
171109	D78	154
~~**174655**~~	~~D1465~~	~~427~~
174655	D419	52
174655	D532	255
174655	D63	300
181667	D1236	340
181667	D1239	340
181667	D231	60
181667	D232	60
181667	D234	60
181667	D235	60
181667	D950	64
800026	D1550	245
800026	D6	136
800026	D768	110
800030	D643	220
800030	D82	315
800030	D83	315
800030	D84	219
800030	D466	62
800030	D467	62
800436	D1122	140
800436	D384	48
800436	D385	24
800436	D388	147
800436	D770	63
~~**800436**~~	~~D777~~	~~146~~

TABLE D-2: Units That Qualify for Conditional Limits in ~~B-Plan or~~ B-Cap using I-Plan Option 4

Facility ID	Device ID	Size (MMBtu/hr)
171107	D220	350
171107	D686	304
171109	D429	352
171109	D78	154
171109	D79	154
174655	C2979	4
174655	D1465	427
174655	D250	89
174655	D33	100
174655	D419	52
174655	D421	82
174655	D532	255
174655	D539	52
174655	D570	650
174655	D63	360
181667	C686	4
181667	C687	4
181667	D1236	340
181667	D1239	340
181667	D231	60
181667	D232	60
181667	D234	60
181667	D235	60
181667	D920	108
181667	D950	64
800026	D1550	245
800026	D1669	342
800026	D378	128
800026	D429	30
800026	D430	200
800026	D53	68
800026	D6	136
800026	D768	110
800026	D98	57
800030	D453	44
800030	D643	220
800030	D82	315
800030	D83	315
800030	D84	219
800030	D466	62
800030	D467	62
800030	D203	-
800436	D1122	140
800436	D214	56
800436	D215	36

Facility ID	Device ID	Size (MMBtu/hr)
800436	D216	31
800436	D217	31
800436	D33	252
800436	D384	48
800436	D385	24
800436	D386	48
800436	D387	71
800436	D388	147
800436	D770	63
800436	D777	146

ATTACHMENT L

Baseline NOx Emissions and Representative NOx Concentrations for Facilities Regulated under Proposed Rule 1109.1 – *Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations*

South Coast AQMD

November 5, 2021

Proposed Rule 1109.1 – *Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations*, establishes NOx concentration limits for refinery equipment. Under Proposed Rule 1109.1 operators have an option to meet the NOx concentrations through alternative compliance plans. One of the compliance plans is an implementation plan called an "I-Plan" which uses Baseline NOx Emissions and Representative NOx Concentrations for each Unit that is included in the I-Plan. This document is a companion to implementation of Rule 1109.1 ensuring agreement as to the baseline NOx emissions and representative NOx concentrations that are needed in calculating the facility's BARCT emission reduction targets required for the I-Plan.

Paragraph (h)(3) of PR 1109.1 references this document, which includes the Baseline NOx Emissions and Representative NOx Concentrations for each Unit for facilities with six or more Units. This document is being presented to the Governing Board for approval, as companion to PR 1109.1, at the Public Hearing for PR 1109.1. Any change to the Baseline NOx Emissions or representative NOx concentrations in this document would require a facility to request in writing to the Executive Office 30 days after rule adoption. Approval of any change to more accurately represent the Baseline NOx Emissions or Representative NOx Concentrations will be based on annual emissions data, CEMS data, source test data, and any other documentation that substantiates the change. If the change, however, is greater than five percent of the corresponding value for the individual unit, that change will need to be presented to the Stationary Source Committee no later than February 18, 2022.

The following tables for the five major petroleum refineries, three related operations, and two smaller refineries present each unit subject to the rule by device ID, equipment category, size, baseline annual NOx emissions, and representative NOx concentration.

Table 1. Chevron Baseline Emissions and Representative NOx Concentrations

CHEVRON				
Device ID	**Category**	**Size (MMBtu/hr)**	**Baseline Annual Emissions (tons)**	**Representative NOx Concentration (ppmv)**
D641	Heater	365	68.3	24
D643	Heater	220	26.2	20.3
D451	Heater	102	37	69.8
D3053	Gas Turbine	506	49	6.4
D203	FCCU	-	49.7	6
D3973	FCC SU Heater	165	-	-
D2198	Gas Turbine	560	41.5	8.3
D20	Heater	217	27.9	31.3
D625	Heater	63	24.9	58.6
D617	Heater	57	23.8	105
D623	Heater	63	23.8	53.8
D2207	Gas Turbine	560	40.2	4.4
D502	Heater	70	21.5	85
D619	Heater	57	19.2	74.3
D504	Heater	77	18.1	83.9
D618	Heater	57	17.5	82.8
D620	Heater	57	17.1	74.3
D2216	Boiler	342	15.5	47.4
D82	Heater	315	6.3	7.9
D83	Heater	315	6.9	7.9
D84	Heater	219	5.4	7.9
D159	Heater	176	14.9	10.4
D160	Heater	176	16.5	10.4
D161	Heater	176	17.1	10.4
D955	SRU/TGI	58	22.4	58.3
D927	SRU/TGI	30	15.7	53
D466	Heater	~~33~~62	3.4	7.8
D467	Heater	~~33~~62	3.6	7.8
D911	SRU/TGI	30	15.4	43.4
D390	Heater	31	6	28.3
D453	Heater	44	3.5	21.3
C3493	Vapor Incinerator	3	3.7	45.1
D1910	Heater	37	3.8	38
D398	Heater	19	3.7	38
C2158	Vapor Incinerator	3	3.1	86.3

CHEVRON				
Device ID	**Category**	**Size (MMBtu/hr)**	**Baseline Annual Emissions (tons)**	**Representative NOx Concentration (ppmv)**
D428	Heater	36	4.4	41.7
D364	Heater	26	2	18.1
C3148	Vapor Incinerator	1	0.018	80.1
C3805	Vapor Incinerator	2	0	-
C3806	Vapor Incinerator	2	0.032	28.3
D3778	Heater	78	0.6	1.3
D3695	Heater	83	0.8	1.9
D473	Heater	88	0.4	1.7
D472	Heater	123	0.7	1.7
D471	Heater	177	0.8	1.7
D3031	Heater	199	1	1.7
D3530	SMR Heater	653	9.1	1.5
D4354	Gas Turbine	509	9.1	1.1
C4344	SRU/TGI	50	2.9	4.2

Table 2. Phillips 66 Baseline Emissions and Representative NOx Concentrations

PHILLIPS 66					
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Annual Emissions (tons)**	**Representative NOx Concentration (ppmv)**
D688	Wilmington	Boiler	250	56	79
D154	Wilmington	Heater	110	16	64
D155	Wilmington	Heater	100	14.5	64
D156	Wilmington	Heater	70	10	64
D157	Wilmington	Heater	42	6	64
D158	Wilmington	Heater	24	3.5	64
D1	Wilmington	FCCU	-	57	14
D44	Wilmington	FCC SU Heater	87	-	-
D687	Wilmington	Boiler	179	41	61
D135	Wilmington	Heater	116	13.6	38
D136	Wilmington	Heater	68	8.2	38
D137	Wilmington	Heater	71	8.6	38
D138	Wilmington	Heater	56	6.6	38
D139	Wilmington	Heater	19	2	38
D684	Wilmington	Boiler	304	29	101
D828	Wilmington	Gas Turbine	646	46	4.5
D264	Wilmington	Heater	135	25	56
D194	Wilmington	Heater	60	20	82
D146	Wilmington	Heater	76	11	30
D686	Wilmington	Boiler	304	9	10
D220	Wilmington	SMR Heater	350	9	8
D333	Wilmington	Sulfuric Acid Furnace	74	9	14
D332	Wilmington	Sulfuric Acid SU Heater	15	0	190
D262	Wilmington	Heater	37	5	37
D148	Wilmington	Heater	27	4.3	37
D259	Wilmington	Heater	39	4.4	37
D152	Wilmington	Heater	30	4	37
D150	Wilmington	Heater	38	3.6	37
D133	Wilmington	Heater	35	3.2	37
D161	Wilmington	Heater	31	3.5	37
D39	Wilmington	Heater	29	2.5	37
D329	Wilmington	Heater	29	2.5	37
D142	Wilmington	Heater	17	2.2	37
D129	Wilmington	Heater	27	1.8	37

PHILLIPS 66					
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Annual Emissions (tons)**	**Representative NOx Concentration (ppmv)**
D163	Wilmington	Heater	14	1.4	37
D260	Wilmington	Heater	17	1.4	37
D40	Wilmington	Heater	10	1	37
D1720	Wilmington	Heater	41	0	3
D1349	Wilmington	SMR Heater	460	9	4
C436	Wilmington	SRU/TGI	20	2	19
C456	Wilmington	SRU/TGI	20	3	15
D430	Carson	Boiler	352	96	77
D210	Carson	SMR Heater	340	90.4	64
D59	Carson	Heater	350	73	40
D174	Carson	Heater	70	18.5	75
D105	Carson	Heater	175	21	30
D104	Carson	Heater	175	19	30
D79	Carson	Heater	154	18	25
D78	Carson	Heater	154	17	23
D429	Carson	Boiler	352	14	10
D713	Carson	Heater	22	1.6	30
C292	Carson	SRU/TGI	15	1	11
C294	Carson	SRU/TGI	28	17	26

- Carson Facility ID: 171109
- Wilmington Facility ID: 171107

Table 3. Marathon Baseline Emissions and Representative NOx Concentrations

MARATHON (TESORO REFINERY)					
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Annual Emissions (tons)**	**Representative NOx Concentration (ppmv)**
D27	Carson	Heater	550	56.5	21
D20	~~Carson~~Calciner	Coke Calciner	120	260.9	65
D570	Carson	SMR Heater	650	48.9	11
D629	Carson	Heater	173	27.5	32
D535	Carson	Heater	310	27.9	23
D532	Carson	Heater	255	20.8	16
D31	Carson	Heater	130	18.3	30
D151	Carson	Heater	130	18.1	36
D155	Carson	Heater	130	17.5	34
D423	Carson	Heater	80	16.5	73
D153	Carson	Heater	130	16.9	33
D67	Carson	Heater	120	15.4	31
D29	Carson	Heater	150	14.8	28
D33	Carson	Heater	100	11.4	24
D539	Carson	Heater	52	5.4	23
D421	Carson	Heater	82	4.6	18
D625	Carson	Heater	39	5.4	23
C54	~~Carson~~SRP	SRU/TGI	52	5.9	68
D250	Carson	Heater	89	3	22
C910	Carson	SRU/TGI	45	25.1	34
C2413	Carson	SRU/TGI	40	14.1	19
D538	Carson	Heater	39	4.2	20
D416	Carson	Heater	24	3.4	28
D626	Carson	Heater	39	3.3	28
D628	Carson	Heater	39	3.4	23
D63	Carson	Heater	360	5.3	5.1
D541	Carson	Heater	39	4.3	16
D1465	Carson	SMR Heater	427	11	5.1
D627	Carson	Heater	39	3.7	17
C56	~~Carson~~SRP	SRU/TGI	45	2.4	98
D419	Carson	Heater	52	1.9	15
D425	Carson	Heater	22	2.4	28
D1433	Carson	Heater	13	1.4	31
D418	Carson	Heater	11	1.3	34
D417	Carson	Heater	10	1.3	17

MARATHON (TESORO REFINERY)					
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Annual Emissions (tons)**	**Representative NOx Concentration (ppmv)**
D1233	Carson	Gas Turbine	1,326	54.8	3
D1239	Carson	Gas Turbine	1,326	53.4	2.7
D1226	Carson	Gas Turbine	1,326	49.7	2.6
D1236	Carson	Gas Turbine	1,326	55.9	2.7
D164	Carson	FCCU	-	7.3	1
D2837	Carson	FCC SU Heater	165	-	-
C2979	Carson	Vapor Incinerator	4	2.6	35
D724/D725	Wilmington	Boiler	368	132.9	114
D722/D723	Wilmington	Boiler	368	108.8	83
D76/D77	SRP	Boiler	225	34.7	48
D812	Wilmington	Gas Turbine	392	65.4	8
D810	Wilmington	Gas Turbine	392	59.6	10
D32	Wilmington	Heater	218	43.1	59
D9	Wilmington	Heater	200	37.5	40
D247	Wilmington	Heater	82	8	43
D248	Wilmington	Heater	50	9.4	43
D249	Wilmington	Heater	29	4.2	43
D146	Wilmington	Heater	69	23.3	134
D33	Wilmington	Heater	252	22.6	17
D388	Wilmington	Heater	147	15.2	16
D214	Wilmington	Heater	56	2.9	17
D215	Wilmington	Heater	36	2.6	17
D216	Wilmington	Heater	31	2	17
D217	Wilmington	Heater	31	4.6	17
D158	Wilmington	Heater	204	9.4	84
D386	Wilmington	Heater	48	2.2	19
D387	Wilmington	Heater	71	3.9	19
D120	Wilmington	Heater	45	8.9	63
D157	Wilmington	Heater	49	8.7	63
D218	Wilmington	Heater	60	7.2	26
D384	Wilmington	Heater	48	2.2	18
D385	Wilmington	Heater	24	1.1	18
D1122	Wilmington	Boiler	140	1.9	7
D777	Wilmington	SMR Heater	146	5.4	7
D250	Wilmington	Heater	35	2.3	31

MARATHON (TESORO REFINERY)					
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Annual Emissions (tons)**	**Representative NOx Concentration (ppmv)**
D770	Wilmington	Heater	63	1.6	7
~~**D386**~~	~~Wilmington~~	~~Heater~~	~~48~~	~~2.2~~	~~19~~
~~**D387**~~	~~Wilmington~~	~~Heater~~	~~71~~	~~3.9~~	~~19~~
~~**D120**~~	~~Wilmington~~	~~Heater~~	~~45~~	~~8.9~~	~~63~~
~~**D157**~~	~~Wilmington~~	~~Heater~~	~~49~~	~~8.7~~	~~63~~
~~**D218**~~	~~Wilmington~~	~~Heater~~	~~60~~	~~7.2~~	~~26~~
~~**D384**~~	~~Wilmington~~	~~Heater~~	~~48~~	~~2.2~~	~~18~~
~~**D385**~~	~~Wilmington~~	~~Heater~~	~~24~~	~~1.1~~	~~18~~
~~**D1122**~~	~~Wilmington~~	~~Boiler~~	~~140~~	~~1.9~~	~~7~~
~~**D777**~~	~~Wilmington~~	~~SMR Heater~~	~~146~~	~~5.4~~	~~7~~
~~**D250**~~	~~Wilmington~~	~~Heater~~	~~35~~	~~2.3~~	~~31~~
~~**D770**~~	~~Wilmington~~	~~Heater~~	~~63~~	~~1.6~~	~~7~~

- Carson Facility ID: 174655
- Wilmington Facility ID: 800436
- Coke Calciner Facility ID: 174591
- Sulfur Recovery Plant (SRP) Facility ID: 151798

Table 4. Torrance Refinery Baseline Emissions and Representative NOx Concentrations

TORRANCE REFINERY				
Device ID	**Category**	**Size (MMBtu/hr)**	**Baseline Annual Emissions (tons)**	**Representative NOx Concentration (ppmv)**
D803	Boiler	309	203.5	116.8
D805	Boiler	291	141.8	35.2
D151	FCCU	-	100.7	10.3
C164	CO Boiler	464	-	-
D2320	FCC SU Heater	132	-	-
D913	Heater	457	48.5	16.3
D914	Heater	161	16.3	16.3
D917	Heater	91	23.9	60.6
D918	Heater	91	24.5	67.6
D120	Heater	126	21	70
D930	Heater	129	23.6	51.2
D83	Heater	67	16.7	52.5
D84	Heater	67	16.2	53
D85	Heater	74	15.4	43.2
D931	Heater	73	13.8	51.2
D269	Heater	107	10.6	43.1
D920	Heater	108	7.1	22.4
D1239	Boiler	340	8	7.2
D1236	Boiler	340	4.9	5.8
C626	Vapor Incinerator	60	7.2	45.4
D949	Heater	40	3.5	23.8
D234	Heater	60	0.5	13.1
D235	Heater	60	1	13.1
D950	Heater	64	1.4	11.7
C686	Vapor Incinerator	4	2.8	38
D927	Heater	17	3	11.7
D231	Heater	60	0.4	13.1
D232	Heater	60	0.5	13.1
D928	Heater	17	2.6	11.7
D929	Heater	21	0.4	27.1
D1403	Heater	21	0.4	27.1
C687	Vapor Incinerator	4	1.2	38
C952	SRU/TGI	100	15.9	19.6

Table 5. Ultramar Baseline Emissions and Representative NOx Concentrations

ULTRAMAR (VALERO)					
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Annual Emissions (tons)**	**Representative NOx Concentration (ppmv)**
D36	Wilmington	FCCU	-	87.7	23.3
D38	Wilmington	FCC SU Heater	100	-	-
D74	Wilmington	Heater	258	30.9	38.4
D3	Wilmington	Heater	159	17.2	30.8
D6	Wilmington	Heater	136	13.5	19
D52	Wilmington	Heater	36	18.9	96
D22	Wilmington	Heater	95	9.5	29.8
D12	Wilmington	Heater	144	8.8	26.7
D53	Wilmington	Heater	68	8.2	23.2
D8	Wilmington	Heater	49	6.3	34.4
D98	Wilmington	Heater	57	5.8	23.1
D768	Wilmington	Heater	110	5.9	10.3
D1550	Wilmington	Boiler	245	5.4	5.2
D73	Wilmington	Heater	30	4.8	20.7
D59	Wilmington	Heater	26	3.2	33.5
D60	Wilmington	Heater	30	3.6	26.2
D429	Wilmington	Heater	30	1	6.3
D430	Wilmington	Heater	200	6.5	6.3
D9	Wilmington	Heater	20	2.5	25.7
D378	Wilmington	Boiler	128	2.6	5.6
C1260	Wilmington	SRU/TGI	36	3	89.8
D377	Wilmington	Boiler	39	0	0
D1669	Wilmington	Gas Turbine	342	3.2	2.1
D179	Asphalt Plant	Heater	15.4	0.03	13.5
D13	Asphalt Plant	Heater	19.3	2.9	20.7
D63	Asphalt Plant	Boiler	14.5	1.9	31
D64	Asphalt Plant	Boiler	14.5	~~0~~1.9	~~0~~30.1

- Wilmington Facility ID: 800026
- Valero Asphalt Plant Facility ID: 800393

Table 6. Air Products Baseline Emissions and Representative NOx Concentrations

Device ID	Facility	Category	Size (MMBtu/hr)	Baseline Annual Emissions (tons)	Representative NOx Concentration (ppmv)
D30	Carson	SMR Heater	764	16.5	3.9
D38	Wilmington	SMR Heater	785	21.6	5.7
D367	Torrance	SMR Heater	527	131.1	53.4
D925/D926*	Torrance	SMR Heater and GTG	1,247	29.9	4.4

***Device ID D925 and D926 share a combined stack, however D926 is owned by Torrance Refinery. Air Products is responsible for the combined stack and emissions for both D925 and D926.**

Table 7. Air Liquide Baseline Emissions and Representative NOx Concentrations

Device ID	Facility	Category	Size (MMBtu/hr)	Baseline Annual Emissions (tons)	Representative NOx Concentration (ppmv)
D24	El Segundo	SMR Heater	780	20	3.7

Table 8. Lunday-Thagard Baseline Emissions and Representative NOx Concentrations

Device ID	Category	Size (MMBtu/hr)	Baseline Annual Emissions (tons)	Representative NOx Concentration (ppmv)
D19	Heater	6	0.87	12
D20	Heater	39.0	12.2	49
D84	Heater	5.5	0.74	58
D214	Boiler	29.4	0.10	7.9
D231	Boiler	39.9	0.78	7.4
C97	Vapor Incinerator	14	11.2	88
C105	Vapor Incinerator	1.4	0.56	101

Table 9. Eco-Services Baseline Emissions and Representative NOx Concentrations

Device ID	Category	Size (MMBtu/hr)	Baseline Annual Emissions (tons)	Representative NOx Concentration (ppmv)
D1	Sulfuric Acid Furnace	150	~~16.5~~23.3	22
D98	SU Heater	50	~~21.6~~0.38	~~49~~94.4
D139	SU Boiler	49	~~0.74~~0.19	29.6
C126	Flare	1.09	~~0.1~~0.22	-

Table 10. Alt Air Baseline Emissions and Representative NOx Concentrations

Device ID	Category	Size (MMBtu/hr)	Baseline Emissions (tons)	Representative NOx (ppmv)
D44	Heater	12.8	-	2.7
D45	Heater	5	-	2.7
D46	Heater	28	0.32	2.7
D374	Boiler	44.5	6.2	71.6
D375	Boiler	44.5	0	-
D376	Boiler	65.9	8.4	105.1
C175	Vapor Incinerator	10	3.7	110
D691	Vapor Incinerator	8	0	-
C882	Vapor Incinerator	1.2	0.12	-
C887	Vapor Incinerator	1.2	0.25	-
C531	Vapor Incinerator	30	4.7	68.2
D569	Vapor Incinerator	8	-	-
D677/D679	Gas Turbine/Duct Burner	140	0	1.7

ATTACHMENT M

(PR 429.1~~Adopted~~ November 5, 2021)
[Rule Index to be included after adoption]

PROPOSED RULE 429.1 STARTUP AND SHUTDOWN PROVISIONS AT PETROLEUM REFINERIES AND RELATED OPERATIONS

(a) Purpose

The purpose of this rule is to provide an exemption from Rule 1109.1 oxides of nitrogen (NOx) and carbon monoxide (CO) concentration~~emission~~ limits and applicable rolling average provisions during startup, shutdown, commissioning, and certain maintenance events and establish requirements during startup, shutdown, and certain maintenance events to limit NOx and CO emissions.

(b) Applicability

The provisions of this rule shall apply to an owner or operator of units at petroleum refineries and facilities with related operations to petroleum refineries.

(c) Definitions

For the purpose of this rule, the following definitions shall apply:

(1) CASTABLE REFRACTORY means refractory that is made by curing liquid material that has been poured into a mold.

(2) CATALYST MAINTENANCE means conditioning, repairing, or replacing the catalyst in NOx post-combustion control equipment associated with a unit which has a bypass stack or duct that exists prior to [*Date of Adoption*].

(3) CATALYST REGENERATION ACTIVITIES means the procedure where air or steam is used to remove coke from the catalyst of a unit or the conditioning of catalyst prior to the startup of a unit.

(4) COMMISSIONING means the first commissioning of a unit, the first commissioning of NOx post-combustion control equipment, or electrical testing associated with upgrades or repairs of cogeneration gas turbines as required by North American Electric Reliability Corporation standards.

(5) FACILITY as defined in Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations.

(6) FACILITY WITH RELATED OPERATIONS TO PETROLEUM REFINERIES as defined in Rule 1109.1.

(7) FEED RATE means the total input of any petroleum derivative feedstock stream to a process unit.

(8~~7~~) FORMER RECLAIM FACILITY as defined in Rule 1109.1.

(9~~8~~) MINIMUM OPERATING TEMPERATURE means the minimum operating temperature specified by the manufacturer, unless otherwise defined in the South Coast AQMD Permit to Construct or Permit to Operate.

(10~~9~~) NEW FACILITY means a facility that begins operation after [*Date of Adoption*].

(11~~0~~) NOx POST-COMBUSTION CONTROL EQUIPMENT means air pollution control equipment which eliminates, reduces, or controls the issuance of NOx after combustion.

(12~~1~~) OXIDES OF NITROGEN (NOx) EMISSIONS as defined in Rule 1109.1.

(13~~2~~) PETROLEUM REFINERY as defined in Rule 1109.1.

~~(13) RATED HEAT INPUT CAPACITY as defined in Rule 1109.1.~~

(14) REFRACTORY DRYOUT means the initial application of heat under controlled rates to safely remove water from refractory lining as part of the curing process prior to placing the unit in service.

(15) SCHEDULED STARTUP means a planned startup that is specified by January 1 of each year.

(16) SHUTDOWN means the time period that begins when an operator reduces the load or heat input, and flue gas temperatures fall below the minimum operating temperature of the NOx post-combustion control equipment, if applicable, and which ends in a period of zero fuel flow or zero feedstock, or when combustion/circulation air flow ends if the unit does not use fuel for combustion.

(17) STABLE CONDITIONS means that the fuel flow, fuel composition, or feedstock to a unit, or the combustion/circulation air if the unit does not use fuel for combustion, is consistent and allows for normal operations.

(18) STARTUP means the time period that begins when a NOx emitting unit combusts fuel, after a period of zero fuel flow or zero feedstock, or when combustion/circulation air is introduced if the unit does not use fuel for combustion, and ends when the flue gas temperature reaches the minimum operating temperature of the NOx post-combustion control equipment and the

unit reaches stable conditions, or when the time limit specified in Table 1 is reached, whichever is sooner.

(19) TUNING means adjusting, optimizing, rebalancing, or other similar operations to a gas turbine or an associated control device or otherwise as defined in a South Coast AQMD Permit to Construct or Permit to Operate. Tuning does not include normal operations to meet load fluctuations.

(20) UNIT means equipment that is subject to Rule 1109.1 which includes boilers, flares, fluid catalytic cracking units (FCCUs), gas turbines, petroleum coke calciners, process heaters, steam methane reformer heaters, sulfuric acid furnaces, sulfur recovery units/tail gas incinerators (SRU/TG incinerators), and vapor incinerators, as defined in Rule 1109.1, requiring a South Coast AQMD Permit to Operate and not required to comply with a NOx emission limit by other South Coast AQMD Regulation XI rules.

(21) WATER FREEING means the procedure of gradually heating a unit to vaporize and remove any accumulated or condensed water in the unit during startup.

(d) Requirements

(1) An owner or operator of a unit is not subject to the NOx and CO concentration~~emission~~ limits in Rule 1109.1 subdivision (d), paragraph (e)(1), paragraph (e)(3),~~paragraphs (d)(3), (d)(4), Table 1, Table 2, Table 3,~~ an approved B-Plan, or an approved B-Cap and the applicable rolling average provisions during the following:

(A) Startup or shutdown;

(B) Maintenance for units with a South Coast AQMD Permit to Operate condition before [*Date of Adoption*] which allows the use of a bypass to conduct maintenance and catalyst maintenance; and

(C) Tuning and commissioning, provided that a South Coast AQMD Permit to Construct or Permit to Operate specifies requirements during tuning and commissioning.

(2) The owner or operator of a unit at a former RECLAIM facility or a new facility shall not exceed the time allowances specified in Table 1 when emissions from the unit exceed the NOx or CO concentration~~emission~~ limits established in Rule 1109.1 during a startup or shutdown.

TABLE 1: STARTUP AND SHUTDOWN DURATION LIMITS

Unit Type	Time Allowance (Hours)
Boilers and Gas Turbines without NOx Post-Combustion Control Equipment, Flares, Vapor Incinerators without NOx Post-Combustion Control Equipment or Castable Refractory	2
Gas Turbines with NOx Post-Combustion Control Equipment	4
Vapor Incinerators with NOx Post-Combustion Control Equipment, Vapor Incinerators with Castable Refractory	20
Process Heaters without NOx Post-Combustion Control Equipment	24
Boilers and Process Heaters with NOx Post-Combustion Control Equipment, Steam Methane Reformer Heaters, Sulfuric Acid Furnaces	48
Steam Methane Reformers with Gas Turbine	60
FCCU Feed Pre-Heater	90
FCCUs, Petroleum Coke Calciners, SRU/TG Incinerators	120

(A) An owner or operator of a unit at a former RECLAIM facility or a new facility shall not allow a startup to last longer than the time to reach stable conditions and to reach the minimum operating temperature of the NOx post-combustion control equipment, if applicable.

(3) An owner or operator of a unit at a former RECLAIM facility or a new facility shall not exceed the maximum number of scheduled startups specified in Table 2 per calendar year for each unit.

TABLE 2: MAXIMUM NUMBER OF SCHEDULED STARTUPS

Unit Type	Maximum Number of Scheduled Startups per Calendar Year
Cogeneration Gas Turbines	10
Process Heaters on Delayed Coking Units	5
All Other Units	2

(4) An owner or operator of a unit at a former RECLAIM facility or a new facility shall take all reasonable and prudent steps to minimize emissions during startup, shutdown, maintenance for units with a South Coast AQMD Permit to Operate condition before [*Date of Adoption*] which allows the use of a bypass to conduct maintenance, catalyst maintenance, tuning, and commissioning.

(5) An owner or operator of a unit at a former RECLAIM facility or a new facility equipped with NOx post-combustion control equipment shall install and maintain an annually calibrated temperature measuring device at the inlet of the NOx post-combustion control equipment.

(6) An owner or operator of a unit at a former RECLAIM facility or a new facility shall operate the NOx post-combustion control equipment, if applicable, including the injection of any associated chemical reagent into the exhaust stream to control NOx, if the temperature of the exhaust gas to the inlet of the NOx post-combustion control equipment is greater than or equal to the minimum operating temperature and the temperature is stable.

(7) An owner or operator of a unit equipped with NOx post-combustion control equipment at a former RECLAIM facility and which has a stack or duct that exists prior to [*Date of Adoption*] that allows for the exhaust gas to bypass the NOx post-combustion control equipment and that elects to use a bypass to conduct catalyst maintenance shall:

(A) Not use a bypass if the unit is scheduled to operate continuously for less than five years between planned maintenance shutdowns of the unit;

(B) Not use a bypass to conduct catalyst maintenance for more than 200 hours in a rolling three-year cycle;

(C) Operate the unit at 50% of the feed rate~~rated heat input capacity~~ of the process unit or less when the NOx post-combustion control equipment is bypassed;

(D) Notify the South Coast AQMD by calling 1-800-CUT-SMOG at least 24 hours prior to bypassing the NOx post-combustion control equipment. This notification shall contain the date and estimated time and duration that the NOx post-combustion control equipment will be bypassed; and

(E) Continuously monitor NOx and CO emissions with a certified Continuous Emissions Monitoring System (CEMS) pursuant to Rule 218.2 – Continuous Emission Monitoring System: General Provisions and Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications or a contractor approved under the South Coast AQMD Laboratory Approval Program (LAP).

(e) Notification

(1) An owner or operator of a unit at a former RECLAIM facility or a new facility shall notify the South Coast AQMD by calling 1-800-CUT-SMOG at least 24 hours prior to a scheduled startup. The notification shall contain the date and time the scheduled startup will begin.

(f) Recordkeeping

(1) An owner or operator of a unit at a former RECLAIM facility or a new facility shall maintain the following records on-site for 5 years and make this information available to the South Coast AQMD upon request:

(A) An operating log for startup, shutdown, refractory dryout, catalyst maintenance, catalyst regeneration activities, tuning, commissioning, and water freeing events which contains the date, time, duration, and reason for each event;

(B) A list of scheduled startups;

(C) A list of planned maintenance shutdowns for the next 5 years for each unit equipped with a bypass stack or duct that exists prior to [*Date of Adoption*]; and

(D) NOx and CO emissions data collected pursuant to subparagraph (d)(7)(E).

(2) An owner or operator of a unit equipped with NOx post-combustion control equipment at a former RECLAIM facility or a new facility shall maintain on-site documentation from the manufacturer of the minimum operating temperature of the NOx post-combustion control equipment and make this information available to the South Coast AQMD upon request, unless the South

Coast AQMD Permit to Construct or Permit to Operate specifies the required minimum operating temperature of the NOx post-combustion control equipment.

(g) Exemptions

(1) An owner or operator of a unit at a former RECLAIM facility or a new facility shall be exempt from the requirements of paragraph (d)(2) during the following:

(A) Refractory dryout;

(B) Catalyst regeneration activities;

(C) Commissioning; and

(D) Water freeing for a maximum of 24 hours.

(2) An owner or operator of a unit equipped with a NOx post-combustion control equipment at a former RECLAIM facility or a new facility with a South Coast AQMD Permit to Operate condition before [*Date of Adoption*] which allows the use of a bypass to conduct maintenance shall be exempt from the requirements of paragraph (d)(7).

(3) An owner or operator of a unit at a former RECLAIM facility or a new facility is exempt from paragraphs (d)(2) and (f)(1) when fuel is burned exclusively in a pilot light.

ATTACHMENT N

(Adopted October 5, 1979)(Amended March 7, 1980)(Amended September 10, 1982)
(Amended July 12, 1985)(Amended January 10, 1986)(Amended August 1, 1986)
(Amended June 28, 1990)(Amended May 3, 1991)(Amended June 5, 1992)
(Amended September 11, 1992)(Amended December 7, 1995)(Amended June 14, 1996)
(PAR 1304 November 5, 2021)

PROPOSED AMENDED RULE 1304. EXEMPTIONS

[Rule Index to be included after amendment]

(a) Modeling and Offset Exemptions

Upon approval by the Executive Officer or designee, an exemption from the modeling requirement of Rule 1303 (b)(1) and the offset requirement of Rule 1303 (b)(2) shall be allowed, for the following sources.

(1) Replacements

The source is replacing a functionally identical source or is a functionally identical modification to a source and there is no increase in maximum ~~rating~~ rated capacity, and the potential to emit of any air contaminant will not be greater from the new source than from the replaced source, when the replaced source was operated at the same conditions and as if current Best Available Control Technology (BACT) were applied.

(2) Electric Utility Steam Boiler Replacement

The source is replacement of electric utility steam boiler(s) with combined cycle gas turbine(s), intercooled, chemically-recuperated gas turbines, other advanced gas turbine(s); solar, geothermal, or wind energy or other equipment, to the extent that such equipment will allow compliance with Rule 1135 or Regulation XX rules. The new equipment must have a maximum electrical power rating (in megawatts) that does not allow basinwide electricity generating capacity on a per-utility basis to increase. If there is an increase in basin-wide capacity, only the increased capacity must be offset.

(3) Abrasive Blasting Equipment

The source is portable abrasive blasting equipment complying with all state laws.

(4) Emergency Equipment

The source is exclusively used as emergency standby equipment for nonutility electrical power generation or any other emergency equipment as approved by the Executive Officer or designee, provided the source does not operate more than 200 hours per year as evidenced by an engine-hour meter or equivalent method.

(5) Air Pollution Control Strategies

The source is subjected to a modification or process change solely to reduce the issuance of air contaminants. This exemption shall not apply to landfill gas control operations or to any modification or process change made for the purpose of achieving regulatory compliance.

(6) Emergencies

The source is exclusively used in emergency operations, such as emergency soil decontamination or excavation, performed by, under the jurisdiction of, or pursuant to the requirements of, an authorized health officer, agricultural commissioner, fire protection officer, or other authorized agency officer. A person shall report any emergency within one hour of such emergency to the District or within one hour of the time said person knew or reasonably should have known of its occurrence. A specific time limit for each operation will be imposed.

(7) Portable Equipment

The source is periodically relocated, and is not located more than twelve consecutive months at any one facility in the District. The residency time of twelve consecutive months shall commence when the equipment is brought into the facility and placed into operation. This paragraph does not apply to portable internal combustion engines.

(8) Portable Internal Combustion Engines

The source is periodically relocated, and is not located more than twelve consecutive months at any one facility in the District, provided that the provisions of subparagraphs (A) through (C) are met. For the purpose of this paragraph, the residency time of twelve months shall commence either when an engine is brought into the facility and placed into operation or removed from storage and placed into operation. The equipment owner or operator shall designate dedicated storage areas within the facility and demonstrate compliance with the residency time requirement by keeping records that show the equipment location and operation history. Such records shall be kept on site for at least two years and made available to the Executive Officer upon request.

(A) Emissions from the engine, by itself, do not cause an exceedance of any ambient air quality standard;

(B) Emissions from the engine do not exceed the following limits:

Volatile Organic Compounds (VOC)	55 pounds per day
Nitrogen Oxides (NO_x)	55 pounds per day
Sulfur Oxides (SO_x)	150 pounds per day
Particulate Matter (PM_{10})	150 pounds per day
Carbon Monoxide (CO)	550 pounds per day

(C) For an engine located in the SEDAB the following limits shall apply:

Volatile Organic Compounds (VOC)	75 pounds per day
Nitrogen Oxides (NO_x)	100 pounds per day
Sulfur Oxides (SO_x)	150 pounds per day
Particulate Matter (PM_{10})	150 pounds per day
Carbon Monoxide (CO)	550 pounds per day

(b) Intra-Facility Portable Equipment

(1) Upon approval by the Executive Officer or designee, using the criteria set forth below, internal combustion engines and gas turbines which must be periodically moved within a facility because of the nature of their operation shall be exempt from the allowable change in air quality concentration requirement as stated in Rule 1303 paragraph (b)(1), provided that all of the following conditions are met:

(A) The engine or turbine is used:

(i) to remediate soil or groundwater contamination as required by federal, state, or local law or by a judicial or administrative order; or

(ii) for flight-line operations.

(B) The engine or turbine is not periodically moved solely for the purpose of qualifying for this exemption.

(C) Emissions from the engine, by itself, do not cause an exceedance of any ambient air quality standard.

(D) Emissions from the engine do not exceed the following limits:

Volatile Organic Compounds (VOC)	55 pounds per day
Nitrogen Oxides (NO_x)	55 pounds per day
Sulfur Oxides (SO_x)	150 pounds per day
Particulate Matter (PM_{10})	150 pounds per day
Carbon Monoxide (CO)	550 pounds per day

(E) For an engine located in the SEDAB the following limits shall apply:

Volatile Organic Compounds (VOC)	75 pounds per day
Nitrogen Oxides (NO_x)	100 pounds per day
Sulfur Oxides (SO_x)	150 pounds per day

Particulate Matter (PM_{10})	150 pounds per day
Carbon Monoxide (CO)	550 pounds per day

(2) For the purpose of clause (b)(1)(A)(ii), flight-line operations mean operations for the ground support of military and commercial aircraft, and includes, but is not limited to, the operation of power-generating internal combustion engines and gas turbines used to support aircraft systems or start up aircraft power plants.

(c) Offset Exemptions

Upon approval by the Executive Officer or designee, an exemption from the offset requirement of Rule 1303(b)(2) shall be allowed, for the following sources.

(1) Relocations

The source is a relocation of an existing source within the District, under the same operator and ownership, and provided that the potential to emit of any air contaminant will not be greater at the new location than at the previous location when the source is operated at the same conditions and as if current BACT were applied. The relocation shall also meet either the location requirements specified in Rule 1303(b)(3), or the applicant must demonstrate to the Executive Officer or designee a net air quality benefit in the area to which the facility will locate.

In addition, the potential to emit of the combined facility for any air contaminant after the relocation shall be less than the amounts in Table A of Rule 1304 (d) whenever either the relocating facility or existing facility received the facility offset exemption pursuant to Rule 1304(d).

(2) Concurrent Facility Modification

The source is part of a concurrent facility modification with emission reductions occurring after the submittal of an application for a permit to construct a new or modified source, but before the start of operation of the source, provided that it results in a net emission decrease, as determined by Rule 1306, and that the same emission reductions are not:

(A) required by a Control Measure of the AQMP which has been assigned a target implementation date; or

(B) required by a proposed District rule for which the first public workshop to consider such a rule has been conducted. This exclusion shall remain in effect for 12 months from the date of the workshop, or until the Executive Officer or designee determines that the proposed rule is abandoned; or

(C) required by an adopted federal, State, or District rule, regulation or statute; or

(D) from a category or class of equipment included in a demonstration program required by a District rule or regulation.

(3) Resource Recovery and Energy Conservation Projects

The source is a cogeneration technology project, resource recovery project or qualifying facility, as defined in Health and Safety Code Sections 39019.5, 39019.6, 39047.5 and 39050.5, to the extent required by state law, including Health and Safety Code Sections 42314, 42314.1, 42314.5, 41605, and 41605.5. In no case shall these sections provide an exemption from federal law.

(4) Regulatory Compliance

The source is installed or modified solely to comply with District, state, or federal air pollution control laws, rules, regulations or orders, as approved by the Executive Officer or designee, and provided there is no increase in maximum ~~rating~~ rated capacity.

(5) Regulatory Compliance for Essential Public Services

The source is installed or modified at an Essential Public Service solely to comply with District, state, or federal pollution control laws, rules, regulations or orders, and verification of such is provided to the Executive Officer or designee; and sufficient offsets are not available in the Priority Reserve.

(6) Replacement of Ozone Depleting Compounds (ODCs)

The source is installed or modified exclusively for the replacement of ODCs, provided the replacement is performed in accordance with the District's ODC Replacement Guidelines. The Executive Officer or designee shall publish and update, as required, such guidelines indicating the administrative procedures and requirements for the replacement of ODCs. The ODC Replacement Guidelines shall ensure to the extent possible that:

(A) the replacements minimize emission increases of VOC, or optimize such emission increases if there is a potential conflict with the requirements of subparagraphs (B), (C) or (D);

(B) the replacements are not toxic, as determined and published by the California Air Resources Board (ARB) or the federal EPA, unless no other alternatives are available;

(C) the replacements do not increase the emissions of other criteria pollutants or global warming compounds; and

(D) there are no adverse or irreversible water quality impacts through the use of such replacements.

(7) Methyl Bromide Fumigation

Any equipment or tarpaulin enclosures installed or constructed exclusively for fumigation using methyl bromide.

(d) Facility Exemption

(1) New Facility

(A) Any new facility that has a potential to emit less than the amounts in Table A shall be exempt from Rule 1303 (b)(2).

(B) Any new facility that has a potential to emit equal to or more than the amounts in Table A shall offset the total amount of emission increase pursuant to Rule 1303 (b)(2).

(2) Modified Facility

(A) Any modified facility that has a post-modification potential to emit less than the amounts in Table A shall be exempt from Rule 1303 (b)(2).

(B) Any modified facility that has a post-modification potential to emit equal to or more than the amounts in Table A shall be required to obtain offsets for the corresponding emissions increase, or the amount in excess of Table A figures if the pre-modification potential to emit was less than the amounts in Table A in accordance with Rule 1303 (b)(2).

TABLE A

Pollutant	Emissions in Tons per Year
Volatile Organic Compounds (VOC)	4
Nitrogen Oxides (NO_x)	4
Sulfur Oxides (SO_x)	4
Particulate Matter (PM_{10})	4
Carbon Monoxide (CO)	29

(3) Determination of emissions pursuant to Table A shall include emissions from permitted equipment excluding Rule 219 equipment not subject to NSR and shall also include emissions from all registered equipment except equipment registered pursuant to Rule 2100.

(4) Emission Increases

Emission increases shall be determined pursuant to Rule 1306(b).

(5) Two-Year Limit on New Facility Exemption

Any new facility with accumulated emission increases in excess of the amounts in Table A due to permit actions within any two-year period after the date of adoption of this rule shall offset the total emission increases during such period to zero.

(e) Emission Reduction Credits Related to Positive NSR Balances

Facilities that previously provided Emission Reduction Credits for the purpose of complying with the requirement to offset positive NSR balances pursuant to Rule 1303(b)(2) after October 1, 1990 shall receive Emission Reduction Credits equal to the amount previously provided to offset their pre-modification positive NSR balance.

(f) Limited BACT Exemption

(1) Upon approval by the Executive Officer or designee, any new or modified permit unit to install add-on air pollution control equipment for control of NOx emissions, shall be exempt from the BACT requirement of Rule 1303 paragraph (a)(1) for any associated increase in PM_{10} and/or SOx emissions caused by or associated with the operation of the add-on air pollution control equipment provided:

(A) The new or modified permit unit is located at a RECLAIM or former RECLAIM facility and is being installed or modified to comply with a South Coast AQMD rule to meet a NOx Best Available Retrofit Control Technology (BARCT) emission limit initially established before December 31, 2023;

(B) The cumulative total maximum rated capacity of all new and modified permit units is less than or equal to the cumulative total maximum rated capacity of the permit unit(s) being replaced and modified, and the new and/or modified permit unit(s) will serve the same purpose as those being replaced and modified. For the new and/or modified permit unit(s) and the permit unit(s) being replaced, a maximum of 90 days is allowed as a start-up period for simultaneous operation;

(C) The facility does not have an increase in physical or operational design capacity, except for those changes needed for the new or modified permit unit(s) that meet the requirement of subparagraph (f)(1)(B). An increase in efficiency is not an increase in the physical and operational design capacity;

(D) Emissions from the new or modified permit unit do not cause an exceedance of any state or national ambient air quality standard, as demonstrated with modeling required in Rule 1303 paragraph (b)(1); and

(E) The new or modified permit unit(s) does not constitute a federal Major Stationary Source or Major Modification as defined in and determined pursuant to the Code of Federal Regulations under Title 40 Part 51 Section 165 or Title 40 Part 52 Section 21. Notwithstanding any other South Coast AQMD rule, when calculating an emission increase for an installation of add-on air pollution control equipment with ammonia, a mass balance calculation may be used provided it employs the percent conversion of SO_2 to SO_3 found in the catalyst manufacturer specifications and uses fuel gas sulfur content representative of actual sulfur content.

(2) All other requirements of Regulation XIII – New Source Review, including but not limited to, permit conditions limiting monthly maximum emissions as required in Rule 1313 – Permits to Operate, shall apply regardless of the limited BACT exemption in paragraph (f)(1).

ATTACHMENT O

(Adopted October 15, 1993)(Amended December 7, 1995)(Amended May 10, 1996)
(Amended July 12, 1996)(Amended February 14, 1997)(Amended April 9, 1999)
(Amended April 20, 2001)(Amended May 6, 2005)(Amended June 3, 2011)
(Amended December 4, 2015)(PAR 2005 November 5, 2021)

PROPOSED AMENDED RULE 2005. NEW SOURCE REVIEW FOR RECLAIM

[Rule Index to be included after amendment]

(a) Purpose

This rule sets forth pre-construction review requirements for new facilities subject to the requirements of the RECLAIM program, for modifications to RECLAIM facilities, and for facilities which increase their allocation to a level greater than their starting Allocation plus non-tradable credits. The purpose of this rule is to ensure that the operation of such facilities does not interfere with progress in attainment of the National Ambient Air Quality Standards, and that future economic growth in the South Coast Air Basin is not unnecessarily restricted.

(b) Requirements for New or Relocated RECLAIM Facilities

(1) The Executive Officer shall not approve the application for a Facility Permit to authorize construction or installation of a new or relocated facility unless the applicant demonstrates that:

(A) Best Available Control Technology will be applied to every emission source located at the facility; and

(B) the operation of any emission source located at the new or relocated facility will not cause a violation nor make significantly worse an existing violation of the state or national ambient air quality standard at any receptor location in the District for NO2 as specified in Appendix A. The applicant shall use the modeling procedures specified in Appendix A.

(2) The Executive Officer shall not approve the application for a Facility Permit authorizing operation of a new or relocated facility, unless the applicant demonstrates that:

(A) the facility holds sufficient RTCs, including any RTCs from Table 9 in Rule 2002, to offset the total facility emissions for the first year of operation, at a 1-to-1 ratio; and

(B) the RTCs procured to comply with the requirements of subparagraph (b)(2)(A) were obtained pursuant to the requirements of subdivision (e), and

(C) the total facility emissions determined to comply with the requirements of subparagraph (b)(2)(A) shall also include ship emissions directly associated with activities at stationary sources subject to this rule as follows:

(i) all emissions from ships during the loading and unloading of cargo and while at berth where the cargo is loaded or unloaded; and

(ii) non-propulsion ship emissions within coastal waters under District jurisdiction.

(c) Requirements for Existing RECLAIM Facilities, Modification to New RECLAIM Facilities, Facilities which Undergo a Change of Operator, or Facilities which Increase an Annual Allocation to a Level Greater Than the Facility's Starting Allocation Plus Non-tradable Credits.

(1) The Executive Officer shall not approve an application for a Facility Permit Amendment to authorize the installation of a new source or modification of an existing source which results in an emission increase as defined in subdivision (d), unless the applicant demonstrates that:

(A) Best Available Control Technology will be applied to the source; and

(B) the operation of the source will not result in a significant increase in the air quality concentration for NO2 as specified in Appendix A. The applicant shall use the modeling procedures specified in Appendix A.

(2) The Executive Officer shall not approve an application for a Facility Permit Amendment to authorize operation of the new or modified source which results in an emission increase as defined in subdivision (d), unless the applicant demonstrates that the facility holds sufficient RTCs to offset the annual emission increase for the first year of operation at a 1-to-1 ratio.

(3) The Executive Officer shall not approve an application for Change of Operator for a Facility Permit unless the applicant demonstrates that the facility holds sufficient RTCs for the compliance year in which the change of operator permit is issued. Credits must be held in an amount equal to:

(A) The annual Allocation initially issued to the original Facility Permit holder for existing facility as defined in Rule 2000 for the same compliance year, in which the change of operator permit is issued, multiplied, where applicable, by the Tradable/Usable RTC Adjustment Factor for the same compliance year as listed in Rule 2002(f)(1)(A); or

(B) The sum of annual RECLAIM pollutants from all the sources located at the facility. The amount of annual RECLAIM pollutants for each source shall be calculated by the maximum hourly potential to emit, over an operating schedule of 24 hours per day and 365 days per year, or shall be based on a permit condition limiting the source's emission.

(4) The Executive Officer shall not approve an application to increase an annual Allocation to a level greater than the facility's starting Allocation plus non-tradable credits, unless the applicant demonstrates that:

(A) each source which creates an emission increase as defined in subdivision (d) will:

(i) apply Best Available Control Technology;

(ii) not result in a significant increase in the air quality concentration for NO2 as specified in Appendix A; and

(B) the facility holds sufficient RTCs acquired pursuant to subdivision (e) to offset the annual increase in the facility's starting Allocation plus non-tradable credits at a 1-to-1 ratio for a minimum of one year.

(5) Notwithstanding the applicability provision contained in Rule 1301 – General paragraph (b)(1), an owner or operator may elect to meet the requirements of Rule 1303 – Requirements paragraph (a)(1) and Rule 1304 – Exemptions paragraph (f)(1), including the limitations in those paragraphs, in lieu of subparagraph (c)(1)(A) of this rule for any associated increase in SOx emissions caused by the operation of any new or modified source with add-on air pollution control equipment exclusively installed to control NOx emissions to meet a Regulation XI rule.

(d) Emission Increase

An increase in emissions occurs if a source's maximum hourly potential to emit immediately prior to the proposed modification is less than the source's post-modification maximum hourly potential to emit. The amount of emission increase will be determined by comparing pre-modification and post-modification emissions on an annual basis by using: (1) an operating schedule of 24 hours per day, 365 days per year; or (2) a permit condition limiting mass emissions.

(e) Trading Zones Restrictions

Any increase in an annual Allocation to a level greater than the facility's starting plus non-tradable Allocations, and all emissions from a new or relocated facility must be fully offset by obtaining RTCs originated in one of the two trading zones as illustrated in the RECLAIM Trading Zones Map. A facility in Zone 1 may only obtain RTCs from Zone 1. A facility in Zone 2 may obtain RTCs from either Zone 1 or 2, or both.

(f) Offsets

The Facility Permit for a new or modified facility shall require compliance with this subdivision, if applicable.

(1) Any facility which was required to provide offsets pursuant to paragraphs (b)(2), or subparagraph (c)(4)(B) or any new facility required to provide offsets pursuant to paragraph (c)(2) shall, at the commencement of each compliance year, hold RTCs, including any RTCs from Table 9 in Rule 2002, in an amount equal to the amount of such required offsets. The Facility Permit holder may reduce the amount of offsets required pursuant to this subdivision by accepting a permit condition limiting emissions which shall serve in lieu of the starting Allocation plus non-tradable credits for purposes of paragraph (c)(4).

(2) Except for the RTCs referenced in Table 9 of Rule 2002, unused RTCs acquired to comply with this subdivision or with paragraphs (b)(2), (c)(2), or subparagraph (c)(4)(B) may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year.

(3) In lieu of compliance with paragraph (f)(2), the Facility Permit holder may accept a permit condition limiting quarterly emissions from the facility. A facility with quarterly emission limits may sell, at any time after the end of that quarter and prior to the end of the reconciliation period for that compliance year, unused RTCs acquired pursuant to this subdivision, excluding the RTCs referenced in Table 9 of Rule 2002, at the amount not to exceed the difference between the permitted emission limit for that quarter and the emissions during that quarter as reported to the District in the Quarterly Emission Certification. Any facility with quarterly certified emissions exceeding the quarterly emission limit for any quarter may sell RTCs, excluding the RTCs referenced in Table 9 of Rule 2002, only during the reconciliation period for the fourth quarter of the applicable compliance year. If there are a total of three exceedances in any five consecutive compliance years, the facility shall permanently comply with paragraph (f)(2) in lieu of (f)(3).

(g) Additional Federal Requirements for Major Stationary Sources

The Executive Officer shall not approve the application for a Facility Permit or an Amendment to a Facility Permit for a new, relocated or modified major stationary source, as defined in the Clean Air Act, 42 U.S.C. Section 7511a(e), unless the applicant:

(1) certifies that all other major stationary sources in the state which are controlled by the applicant are in compliance or on a schedule for compliance with all applicable federal emission limitations or standards (42 U.S.C. Section 7503(a)(3)); and

(2) submits an analysis of alternative sites, sizes, production processes and environmental control techniques for the proposed source which demonstrates that the benefits of the proposed source significantly outweigh the environmental and social cost imposed as a result of its location, construction, or modification (42 U.S.C. Section 7503(a)(5));

(3) Compliance Through California Environmental Quality Act

The requirements of paragraph (g)(2) may be met through compliance with the California Environmental Quality Act in the following manner.

(A) if the proposed project is exempt from California Environmental Quality Act analysis pursuant to a statutory or categorical exemption pursuant to Title 14, California Code of Regulations, Sections 15260 to 15329, paragraph (g)(2) shall not apply to that project;

(B) if the proposed project qualifies for a negative declaration pursuant to Title 14 California Code of Regulations, Section 15070, or a mitigated negative declaration as defined in Public Resources Code Section 21064.5, paragraph (g)(2) shall not apply to that project; or

(C) if the proposed project has been analyzed by an environmental impact report pursuant to Public Resources Code Section 21002.1 and Title 14 California Code of Regulations, Section 15080 et seq., paragraph (g)(2) shall be deemed satisfied.

(4) Protection of Visibility

(A) Conduct a modeling analysis for plume visibility in accordance with the procedures specified in Appendix B if the net emission increase from the new or modified source exceeds 40 tons/year of NO_X; and the location of the source, relative to the closest boundary of a specified_Federal Class I area, is within the distance specified in Table 4-1.

Table 4-1

Federal Class I Area	*Distance (km)*
Agua Tibia	28
Cucamonga	28
Joshua Tree	29
San Gabriel	29
San Gorgonio	32
San Jacinto	28

(B) In relation to a permit application subject to the modeling analysis required by subparagraph (g)(4)(A), the Executive Officer shall:

(i) deem a permit application complete only when the applicant has complied with the requisite modeling analysis for plume visibility pursuant to subparagraph (g)(4)(A);

(ii) notify and provide a copy of the complete permit application file to the applicable Federal Land Manager(s) within 30 calendar days after the application has been deemed complete and at least 60 days prior to final action on the permit application;

(iii) consider written comments, relative to visibility impacts from the new or modified source, from the responsible Federal Land Manager(s), including any regional haze modeling performed by the Federal Land Manager(s), received within 30 days of the date of notification when determining the terms and conditions of the permit;

(iv) consider the Federal Land Manager(s) findings with respect to the geographic extent, intensity, duration, frequency and time of any identified visibility impairment of an affected Federal Class I area, including how these factors correlate with times of visitor use of the Federal Class I area, and the frequency and timing of natural conditions that reduce visibility; and,

(v) explain its decision or give notice as to where to obtain this explanation if the Executive Officer finds that the Federal Land Manager(s) analysis does not demonstrate that a new or modified source may have an adverse impact on visibility in an affected Federal Class I area.

(C) If a project has an adverse impact on visibility in an affected Federal Class I area, the Executive Officer may consider the cost of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, the useful life of the source, and all other relevant factors in determining whether to issue or deny the Permit to Construct or Permit to Operate.

(h) Public Notice

The applicant shall provide public notice, if required, pursuant to Rule 212 - Standards for Approving Permits.

(i) Rule 1401

All new or modified sources shall comply with the requirements of Rule 1401 - New Source Review of Carcinogenic Air Contaminants, if applicable.

(j) Compliance with State and Federal New Source Review Requirements

The Executive Officer will report to the District Governing Board regarding the effectiveness of Rule 2005 in meeting the state and federal New Source Review requirements for the preceding year. The Executive Officer may impose permit conditions to monitor and ensure compliance with such requirements. This report shall be incorporated in the Annual Program Audit Report prepared pursuant to Rule 2015(b)(1).

(k) Exemptions

(1) Functionally identical source replacements are exempt from the requirements of subparagraph (c)(1)(B) of this rule.

(2) Physical modifications that consist of the installation of equipment where the modification will not increase the emissions rate of any RECLAIM pollutant, and will not cause an increase in emissions above the facility's current year Allocation, shall be exempt from the requirements of paragraph (c)(2).

(3) Increases in hours of operation or throughput for equipment or processes permitted prior to October 15, 1993 that the applicant demonstrates would not violate any permit conditions in effect on October 15, 1993 which were imposed in order to limit emissions to implement New Source Review offset requirements, shall be exempt from the requirements of this rule.

(4) Increase to RECLAIM emission concentration limits or emission rates not associated with Best Available Control Technology permit conditions provided that the increase is not a result of any modification to equipment shall be exempt from the requirements of this rule.

(5) The requirements under subparagraphs (b)(1)(B) and (c)(1)(B), and clause (c)(4)(A)(ii) shall not apply to equipment used exclusively on a standby basis for non-utility electrical power generation or any other equipment used on a standby basis in case of emergency, provided the source does not operate more than 200 hours per year as evidenced by an engine-hour meter or equivalent method and is listed as emergency equipment in the Facility Permit.

APPENDIX A

The following sets forth the procedure for complying with the air quality modeling requirements. An applicant must either (1) provide an analysis approved by the Executive Officer or designee, or (2) show by using the Screening Analysis below, that a significant change (increase) in air quality concentration will not occur at any receptor location for which the state or national ambient air quality standard for NO_2 is exceeded.

Table A-1 of the screening analysis is subject to change by the Executive Officer, based on improved modeling data.

SCREENING ANALYSIS

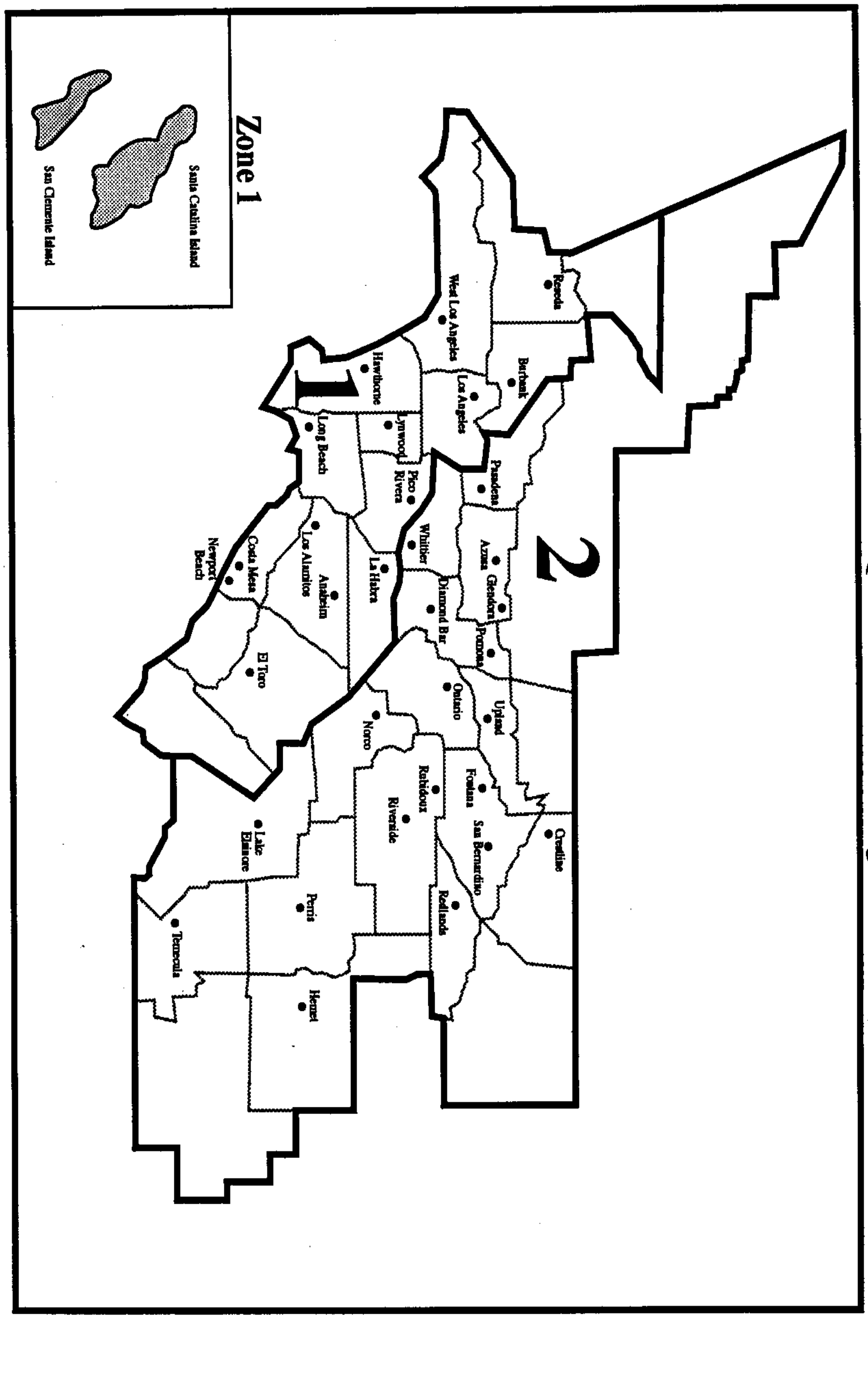
Compare the emissions from the equipment you are applying for to those in Table A-1. If the emissions are less than the allowable emissions, no further analysis is required. If the emissions are greater than the allowable emissions, a more detailed air quality modeling analysis is required.

Table A-1
Allowable Emissions
for Noncombustion Sources and for
Combustion Sources less than 40 Million BTUs per hour

Heat Input Capacity (million BTUs/hr)	NOx (lbs/hr)
Noncombustion Source	0.068
2	0.20
5	0.31
10	0.47
20	0.86
30	1.26
40	1.31

Table A-2
Most Stringent Ambient Air Quality Standard and
Allowable Change in Concentration
For Each Air Contaminant/Averaging Time Combination

Air Contaminant	Averaging Time	Most Stringent Air Quality Standard		Significant Change in Air Quality Concentration	
Nitrogen	1-hour	25 pphm	500 ug/m^3	1 pphm	20 ug/m^3
Dioxide	Annual	5.3 pphm	100 ug/m^3	0.05 pphm	1 ug/m^3



RECLAIM Trading Zones
South Coast AQMD Air Monitoring Stations

APPENDIX B

MODELING ANALYSIS FOR VISIBILITY

(a) The modeling analysis performed by the applicant shall consider:

(1) the net emission increase from the new or modified source; and

(2) the location of the source and its distance to the closest boundary of specified Federal Class I area(s)**.**

(b) Level 1 and 2 screening analysis for adverse plume impact pursuant to paragraph (g)(4) of this rule for modeling analysis of plume visibility shall consider the following applicable screening background visual ranges:

Federal Class I Area	Screening Background Visual Range (km)
Agua Tibia	171
Cucamonga	171
Joshua Tree	180
San Gabriel	175
San Gorgonio	192
San Jacinto	171

For level 1 and 2 screening analysis, no adverse plume impact on visibility results when the total color contrast value (Delta-E) is 2.0 or less and the plume contrast value (C) is 0.05 or less. If these values are exceeded, the Executive Officer shall require additional modeling. For level 3 analysis the appropriate background visual range, in consultation with the Executive Officer, shall be used. The Executive Officer may determine that there is no adverse visibility impact based on substantial evidence provided by the project applicant.

(c) When more detailed modeling is required to determine the project's visibility impact or when an air quality model specified in the Guidelines below is deemed inappropriate by the Executive Officer for a specific source-receptor application, the model may be modified or another model substituted with prior written approval by the Executive Officer, in consultation with the federal Environmental Protection Agency and the Federal Land Managers.

(d) The modeling analysis for plume visibility required pursuant to paragraph (g)(4) of this rule shall comply with the most recent version of:

(1) "Guideline on Air Quality Model (Revised)" (1986), supplement A (1987), supplement B (1993) and supplement C (1994), EPA-450/2-78-027R, US EPA, Office of Air Quality Planning and Standards Research Triangle Park, NC 27711; and

(2) "Workbook for Plume Visual Impact Screening and Analysis (Revised)," EPA-454-/R-92-023, US EPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711;

(3) "User's Manual for the Plume Visibility Model (PLUVUE II) (Revised)," EPA-454/B-92-008, US EPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711 (for Level-3 Visibility Analysis)

ATTACHMENT P

(Adopted March 12, 1984)(Amended Dec. 7, 1984)((Invalidated Jan. 9, 1985)
(Adopted November 1, 1985)(Amended August 5, 1988)
(Rescinded November 5, 2021)

PROPOSED RESCINDED RULE 1109. EMISSIONS OF OXIDES OF NITROGEN FROM BOILERS AND PROCESS HEATERS IN PETROLEUM REFINERIES

Rescinded by the South Coast Air Quality Management District Board on November 5, 2021.

ATTACHMENT Q

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Staff Report

Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations and Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries

November 2021

Deputy Executive Officer
Planning, Rule Development, and Area Sources
Sarah Rees, Ph.D.

Assistant Deputy Executive Officer
Planning, Rule Development, and Area Sources
Susan Nakamura

Planning and Rules Manager
Planning, Rule Development, and Area Sources
Michael Krause

Authors:	Heather Farr – Program Supervisor Sarady Ka – Air Quality Specialist Mojtaba Moghani, Ph.D. – Air Quality Specialist Zoya Banan, Ph.D. – Air Quality Specialist
Contributors:	Bhaskar Chandan – Senior Air Quality Engineering Manager Tran Vo – Supervising Air Quality Engineer Shah Dabirian, Ph.D. – Program Supervisor Barbara Radlein – Program Supervisor Dipankar Sarkar – Program Supervisor Thomas Truppi – Air Quality Engineer II Mika MacFarlane – Air Quality Engineer I Ryan Finseth, Ph.D. – Air Quality Specialist Kevin Ni – Air Quality Specialist
Reviewed By:	Barbara Baird – Chief Deputy Counsel William Wong – Principal Deputy District Counsel Brian Tomasovic – Principal Deputy District Counsel

FURTHER ACKNOWLEDGMENTS

South Coast Air Quality Management District
(South Coast AQMD)

Jason Aspell – DEO, Engineering & Permitting
Jillian Wong, Ph.D. – ADEO, Engineering & Permitting
Philip M. Fine, Ph.D. – (former) DEO, PRDAS
Amir Dejbakhsh – (former) DEO, Engineering & Permitting
Mike Garibay – Source Testing Manager, Source Testing (Ret.)
Danny Luong – (former) Senior Engineering Manager, Engineering & Permitting
Mike Morris – Planning & Rules Manager, PRDAS
Kevin Orellana – Senior Enforcement Manager, Compliance and Enforcement
David Ono – Senior Enforcement Manager, Engineering & Permitting
Uyen-Uyen Vo – Program Supervisor, PRDAS
Gary Quinn – Program Supervisor, PRDAS
Rudy Chacon – Program Supervisor, PRDAS
Jong Hoon Lee, Ph.D. – Air Quality Specialist, PRDAS
Shawn Wang – Air Quality Specialist, PRDAS
Yanrong Zhu – Air Quality Specialist, PRDAS
Lizabeth Gomez – Air Quality Specialist, PRDAS
Khang Nguyen – Senior Air Quality Engineer, Refinery Team
Tom Lee – Senior Air Quality Engineer, Refinery Team
Al Baez – Program Supervisor, Engineering & Permitting
Mike Wickson – Senior Air Quality Engineer, Source Testing
Glenn Kasai – Senior Air Quality Engineer, Source Testing (Ret.)
Tom Lee – Program Supervisor, Science & Technology Advancement

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
GOVERNING BOARD

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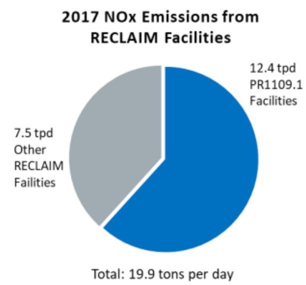
List of Acronyms

B-CAP	BARCT Equivalent Mass Cap Plan
B-PLAN	BARCT Equivalent Compliance Plan
BARCT	Best Available Retrofit Control Technology
CEMS	Continuous Emissions Monitoring System
CEQA	California Environmental Quality Act
CM	Control Measure
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DCF	Discounted Cash Flow
DLN/DLE	Dry Low NOx/Dry Low Emissions
DOE	U.S. Department of Energy
ESP	Electrostatic Precipitator
°F	Degree Fahrenheit
FERCo	Fossil Energy Research Corporation
FCCU	Fluid Catalytic Cracking Unit
HAP	Hazardous Air Pollutant
HHV	High Heating Value of Fuel
HRSG	Heat Recovery Steam Generator
I-PLAN	Implementation Compliance Plan
GC/TCD	Gas Chromatograph-Thermal Conductivity Detector
LCF	Levelized Cash Flow
LNB	Low NOx Burner
LoTOx™	Low Temperature Oxidation Process for NOx Control
MMBtu	Metric Million British Thermal Unit
MMscf	Million Standard Cubic Feet
NAAQS	National Ambient Air Quality Standards
NEC	Norton Engineering Consultants Inc.
NG	Natural Gas
NH_3	Ammonia
N_2O	Nitrous Oxide
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NOx	Nitrogen Oxides
O_2	Oxygen
PM2.5	Particulate Matter with diameter of 2.5 micrometers or smaller
PM10	Particulate Matter with diameter of 10 micrometers or smaller
ppmv	Parts Per Million by Volume
PR	Proposed Rule
PSA	Pressure Swing Adsorption
PWV	Present Worth Value
RECLAIM	Regional Clean Air Incentive Market Program
RFG	Refinery Fuel Gas
RTC	RECLAIM Trading Credit
South Coast AQMD	South Coast Air Quality Management District
SCR	Selective Catalytic Reduction

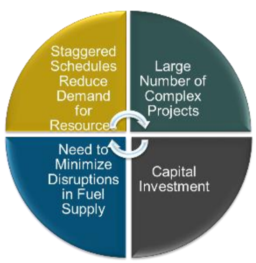
SIP	State Implementation Plan
SMR	Steam Methane Reformer
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SOx	Sulfur Oxides
SRU/TG	Sulfur Recovery Unit /Tail Gas
SSM	Startup, Shutdown, and Malfunction
TIC	Total Installed Costs
tpd or TPD	Tons Per Day
ULNB	Ultra-Low NOx Burner
UltraCat™	UltraCat™ Catalyst Filter Manufactured by Tri-Mer Corporation
U.S. EPA	U.S. Environmental Protection Agency
VOC	Volatile Organic Compound
WGM	Working Group Meeting
WHB	Waste Heat Boiler
WSPA	Western States Petroleum Association

EXECUTIVE SUMMARY

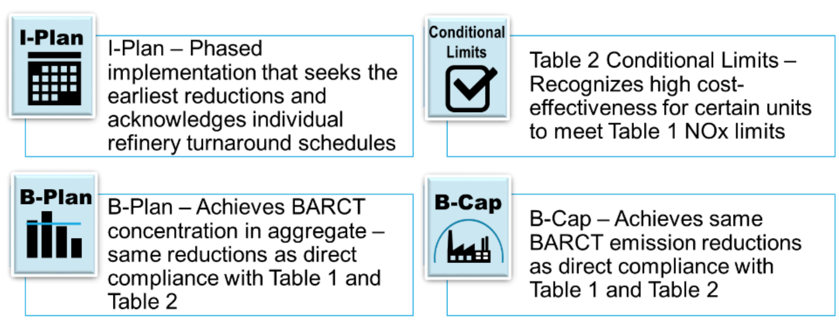
Control Measure CMB-05 of the Final 2016 Air Quality Management Plan (AQMP) included a five tons per day Nitrogen Oxides (NOx) emission reduction as soon as feasible but no later than 2025, and directive to transition the REgional Clean Air Incentives Market (RECLAIM) program to a command-and control regulatory structure requiring Best Available Retrofit Control Technology (BARCT) as soon as practicable. California State Assembly Bill 617, approved by the Governor on July 26, 2017, requires air districts to develop, by January 1, 2019, an expedited schedule for the implementation of BARCT no later than December 31, 2023 for facilities that are in the state greenhouse gas cap-and-trade program.



The REgional Clean Air Incentives Market (RECLAIM) program, which is under Regulation XX - RECLAIM –(Regulation XX), was adopted in October 1993 and is a market-based emissions trading program designed to reduce NOx and Sulfur Oxides (SOx) emissions. Petroleum refineries and facilities with related operations to petroleum refineries represent the largest source of NOx emissions in the RECLAIM program.



Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR 1109.1) establishes NOx and Carbon Monoxide (CO) concentration limits that represent BARCT for combustion equipment located at sixteen petroleum refineries and facilities with operations related to petroleum refineries (e.g., sulfur recovery plants). The established BARCT NOx limits will require approximately 220 pieces of NOx equipment to be retrofitted with pollution controls which range from $10 million to $70 million per project, and $179 million to $1 billion per refinery. In addition, these complex projects require significant engineering, design, planning, logistics, funding, order/delivery, installation, and commissioning.



To address complexity of the pollution control projects, significant capital investments needed, need to minimize disruptions in fuel supply, and competition for the same resources, PR 1109.1 includes several compliance options: Conditional NOx limits for certain units that can meet specific conditions, an alternative implementation plan called an I-Plan, and two alternative BARCT emissions plans called a B-Plan and a B-Cap. Once fully implemented, PR 1109.1 is estimated to achieve approximately 7.7 to 7.9 tons per day of NOx emission reductions. It is expected that about 75 percent of the reductions would occur in 2027.

PR 1109.1 was developed through a public process that included 25 Working Group Meetings with nearly 100 meetings with environmental and community groups, CARB, U.S. EPA, individual facilities, and industry groups to gather direct input and help build consensus for the proposed rule.

CHAPTER 1 BACKGROUND

INTRODUCTION

The South Coast Air Quality Management District (South Coast AQMD) Governing Board adopted the Regional Clean Air Incentives Market (RECLAIM) program in October 1993. The purpose of RECLAIM was to reduce Nitrogen Oxides (NOx) and Sulfur Oxides (SOx) emissions through a market-based approach for facilities with NOx or SOx emissions greater than or equal to four tons per year. The program replaced a series of existing and future command-and-control rules and was designed to provide facilities with compliance flexibility. RECLAIM was designed to achieve emission reductions in aggregate equivalent to what would occur under a command-and-control regulatory approach. Regulation XX – REgional Clean Air Incentives Market (RECLAIM) (Regulation XX) includes a series of rules that specify the applicability and procedures for determining NOx and SOx facility emissions allocations, program requirements, as well as monitoring, reporting, and recordkeeping requirements for RECLAIM facilities.

In response to the growing concern that hundreds of units in RECLAIM are currently operating above NOx Best Available Retrofit Control Technology (BARCT) emission levels, Control Measure CMB-05 of the 2016 AQMP committed to identify approaches to make the program more effective in ensuring equivalency with command-and-control regulations implementing BARCT and to provide an assessment of the RECLAIM program in order to achieve further NOx emission reductions of five tons per day (tpd). During the adoption of the 2016 AQMP, the Resolution directed staff to modify Control Measure CMB-05 to achieve the five tons per day NOx emission reduction as soon as feasible but no later than 2025, and to transition the RECLAIM program to a command-and-control regulatory structure requiring BARCT-level controls as soon as practicable.[1]

On July 26, 2017, California State Assembly Bill 617 – Nonvehicular Air Pollution: Criteria Air Pollutants and Toxic Air Contaminants (AB 617) was approved by the Governor, which addresses nonvehicular air pollution (criteria pollutants and toxic air contaminants). It is a companion legislation to Assembly Bill 398 – California Global Warming Solutions Act of 2006 (AB 398), which was also approved, and extends California's cap-and-trade program for reducing greenhouse gas emissions from stationary sources. RECLAIM facilities that are in the cap-and-trade program are subject to the requirements of AB 617. Requirements include an expedited schedule for implementing BARCT for cap-and-trade facilities and a requirement for the Air Districts throughout California to adopt an expedited BARCT schedule by January 1, 2019, to implement BARCT no later than December 31, 2023 by assigning the highest priority to those permitted units that have not modified emissions related permit conditions for the greatest period of time.

PR 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR 1109.1) will facilitate the transition of petroleum refineries and facilities with related operations to petroleum refineries to a command-and-control regulatory structure and partially implement Control Measure CMB-05 of the 2016 AQMP. Petroleum refineries and facilities with related operations to petroleum refineries are included in California's cap-and-trade program. PR 1109.1 applies to NOx emitting combustion equipment at facilities, including asphalt plants, biofuel plants, hydrogen production plants, petroleum refineries, facilities that operate petroleum coke calciners, sulfuric acid plants, and sulfur recovery plants. The proposed rule will establish NOx and Carbon Monoxide (CO) emission limits to reflect BARCT for most combustion

[1] http://www.aqmd.gov/docs/default-source/Agendas/Governing-Board/2017/2017-apr7-001.pdf?sfvrsn=2

equipment categories at these facilities. Additionally, PR 1109.1 establishes provisions for monitoring, recordkeeping, and reporting and provides alternative implementation and compliance approaches including an Implementation Compliance Plan (I-Plan), BARCT Equivalent Compliance Plan (B-Plan), and BARCT Equivalent Mass Cap Plan (B-Cap).

REGULATORY BACKGROUND

Rule 1109 – Background

On November 1, 1985, South Coast AQMD adopted the Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries (Rule 1109). The rule was last amended on August 5, 1988. Rule 1109 was applicable to all boilers and process heaters in petroleum refineries and established a NOx refinery-wide emission limit of 0.14 lb/MMBtu (approximately 120 ppmv NOx corrected to three percent O_2) for the units operated on gaseous fuel, 0.308 lb/MMBtu (approximately 250 ppmv NOx corrected to three percent O_2) for the units operated on liquid fuel, and the weighted average of these limits for the units operated concurrently on both liquid and gaseous fuels when the units are firing at the maximum rated capacity. After December 31, 1995, the limit for gaseous fuels is reduced to 0.03 lb/MMBtu when firing on the maximum rated capacity. Rule 1109 includes provisions that the mass emissions cannot be greater than the mass emissions that are representative of 0.03 lb/MMBtu at the maximum rated capacity. In addition, Rule 1109 included an Alternative Emissions Control Plan that allowed an operator to submit a methodology that could provide equivalent emission reductions than the NOx standards in the rule. Since RECLAIM was adopted in 1993, the 1995 NOx standard of 0.03 lb/MMBtu was never implemented. No Alternative Emissions Control Plans were submitted and approved under Rule 1109.

RECLAIM Program

The RECLAIM program is a market-based program that was adopted in 1993 and applies to facilities with NOx and SOx annual emissions greater than or equal to four tons per year and is designed to achieve BARCT in aggregate. When the NOx RECLAIM program was adopted, facilities were issued an annual allocation of RECLAIM Trading Credits (RTCs), which declined annually from 1993 until 2003 and remained constant after 2003. At the end of each compliance year, facilities in the RECLAIM program must hold RTCs that are equal to or greater than the facility’s actual emissions. Under RECLAIM, facilities have the option to purchase RTCs, reduce throughput, implement process modifications, or install pollution controls to reduce emissions. RECLAIM is designed to achieve BARCT in aggregate. When RECLAIM was adopted, all petroleum refineries and facilities with operations related to petroleum facilities (related facilities) transitioned to this market-based program.

Pursuant to Health and Safety Code Section 40440 and 39616, South Coast AQMD is required to periodically assess the advancement in control technologies that are representative of BARCT to ensure that RECLAIM facilities achieve the same emission reductions that would have occurred under a command-and-control approach and that RECLAIM sources contribute to the efforts in the Basin to achieve the federal National Ambient Air Quality Standards (NAAQS). Over the course of RECLAIM, there have been two BARCT reassessments for NOx in 2005 and 2015.

2005 NOx Shave

Assessment of actual NOx emission reductions as a result of the amendments to the NOx RECLAIM program in 2005 demonstrated that allowing for the use of shutdown RTCs in a market where many facilities have not yet installed BARCT controls can further delay or eliminate the need for facilities to install equipment to reduce their NOx emissions. The NOx RTC shave target for the 2005 amendments was 7.7 tons per day from 2007 to 2011. The actual NOx emission reductions between the timeframe of 2006 and 2012 was 4 tons per day. Of these 4 tons per day, 2.6 tons per day (or 65%) originated from facility shutdowns, while 1.4 tons per day (or 35%) came from either emission controls, process changes, or from a decrease in production levels due to the recession[2].

2015 NOx Shave

On December 4, 2015, Regulation XX was amended to reduce NOx allocations for the largest NOx emitters by 12 tons per day. Refineries and related industries represented approximately 7.9 tons per day (66 percent) of the 12 tons per day. The table below shows the NOx reduced levels for different combustion units under RECLAIM in 2005 and 2015 BARCT assessments and NOx shaves.

Table 1-1. 2005 and 2015 RECLAIM BARCT Levels

Unit	2005 NOx Level	2015 NOx Level	Oxygen Correction (%)
Fluid Catalytic Cracking Units	85% reduction	2 ppmv	3
Refinery Boilers and Process Heaters	5 ppmv	2 ppmv	3
Refinery Gas Turbines	N/A	2 ppmv	15
Petroleum Coke Calciner	30 ppmv	10 ppmv	3
Sulfur Recovery Units/Tail Gas Incinerators	N/A	2 ppmv	3

The intent of the BARCT reassessments was to ensure the RECLAIM program achieves BARCT in aggregate; however, evaluation of the units at petroleum refineries and related industries indicate 88 percent of the equipment at those facilities are not operating at levels representative of BARCT.

Implementation of the 2015 shave is designed to reduce NOx allocations by 12 tons per day from 2016 to 2022. The reduction in NOx allocations were greater towards the end of the shave period, with the greatest reductions occurring in 2022. Implementation of a shave does not necessary imply that a source will install pollution controls or reduce emissions as facilities under RECLAIM have the option to purchase RTCs. The 2015 NOx shave was expected to reduce NOx as follows:

- 2016: 2 tons per day
- 2017: 0 tons per day
- 2018: 1 ton per day
- 2019: 1 ton per day
- 2020: 2 tons per day
- 2021: 2 tons per day
- 2022: 4 tons per day

[2] http://www.aqmd.gov/docs/default-source/Agendas/Governing-Board/2016/2016-Oct7-037.pdf?sfvrsn=9

2016 Regulation XX Amendments

During the 2015 rule development of Regulation XX to incorporate the 12 tons per day shave, concerns were raised that use of RTCs from shutdowns was contributing to the delay in installation of pollution controls. RECLAIM staff estimated that the shutdown of Cal Portland Cement allowed over 2 tons per day of RTCs to become available for sale and were subsequently purchased by other facilities to meet compliance obligations rather than installation of BARCT controls. To address RTCs from facility shutdowns, in October 2016, Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx) (Rule 2002), which is one of the rules within Regulation XX, was amended to address the treatment of RTCs upon NOx RECLAIM facility shutdowns. The objective of the amendments was to prevent the RTCs associated with facility shutdowns from entering the market and delaying the installation of pollution controls at other NOx RECLAIM facilities. The amendments established the criteria for determining a facility shutdown (i.e., permanent or temporary) and the methodology to calculate the amount of reduction of future NOx RTCs holdings.

2018 Regulation XX Amendments

On January 5, 2018, the Board adopted amendments to Rules 2001 – Applicability (Rule 2001) and 2002. Amendments to Rule 2001 ended the addition of any facilities into RECLAIM, and Rule 2002 included provisions to establish the overall process to transition facilities from the RECLAIM program to a command-and-control regulatory structure. Before a facility can be transitioned out of RECLAIM, the facility must either have all equipment at BARCT or be subject to a rule that establishes BARCT requirements for all their equipment. Subsequently, U.S. EPA informed staff that RECLAIM facilities could not transition out of the program until the entire program had been amended and State Implementation Plan (SIP)-approved, so this provision was amended to not allow transitioning out of RECLAIM.

RECLAIM Emission Reductions

The RECLAIM program was designed to achieve BARCT in the aggregate and the intent of the BARCT reassessments was to ensure emission reductions were achieved that are equivalent to BARCT. However, evaluation of the units at petroleum refineries and related industries indicate 88 percent of the equipment at those facilities are not operating at levels representative of BARCT. As of August 2021, only 22 permits have been submitted from petroleum refineries and related industries for large NOx reduction projects (e.g., selective catalytic reduction (SCR) projects and low-NOx burners), compared to the 91 SCR projects assumed to be needed to achieve the NOx shave. Upon completion, those 22 projects will account for approximately 2.43 tons per day of NOx reduced. Further, 10 out of the approximately 100 boilers and process heaters 40 MMBtu/hour or greater are currently at or below 5 ppmv NOx or less.

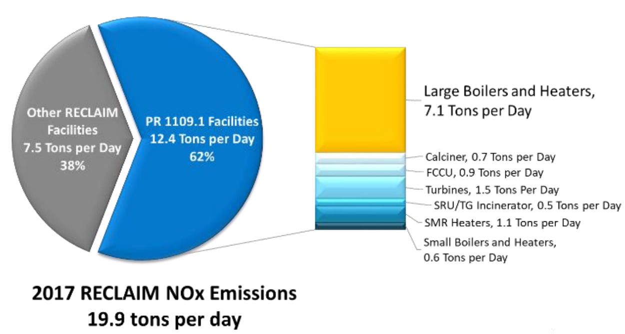


Figure 1. Percentage of NOx Emissions by Equipment Category

Figure 1-1 shows the percentage of emissions from each equipment category in Proposed Rule 1109.1. The highest emitting category of equipment at petroleum refineries and related facilities are process heaters and boilers that are rated at 40

MMBtu/hour or greater; this category accounts for approximately 58 percent of the total NOx emissions.

Figure 1-2 shows the NOx concentrations of boilers and heaters rated at or greater than 40 MMBtu/hour. Staff found that 95 percent of those units are currently not meeting a 5 ppmv or 2 ppmv NOx limits determined to represent the BARCT limits during the 2005 and 2015 RECLAIM BARCT assessment respectively.

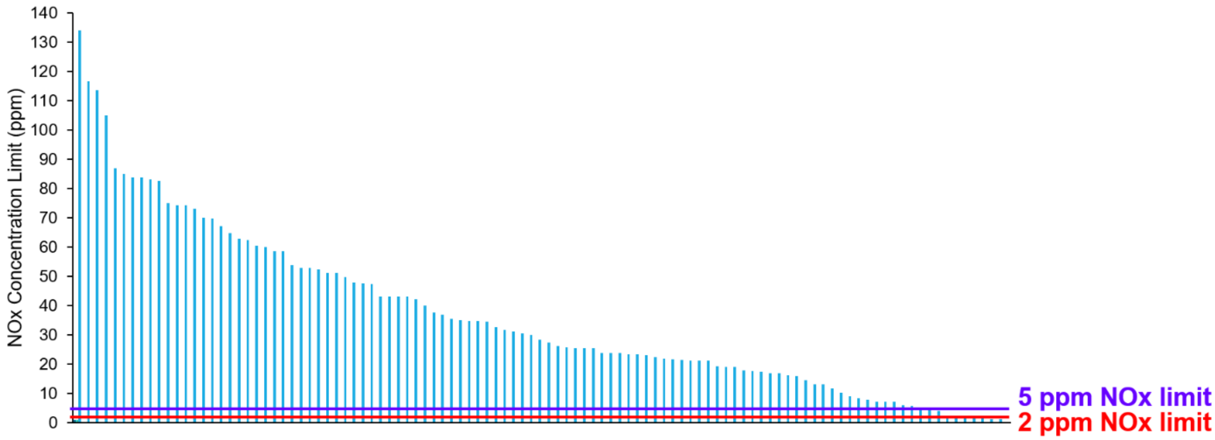


Figure 2. NOx Concentration Levels of Boilers and Heaters ≥40 MM Btu/hr

The trend of annual NOx emissions from the seven highest emitting refineries subject to PR 1109.1 since RECLAIM adoption in 1993 to 2019 is provided in the Figure 1-3. Estimated emissions in 1995 were higher than the ones in 1993 due to the prevalence of the use of missing data and difficulties associated with installation and certification of continuous emission monitoring systems (CEMS). Reported annual emissions decreased in the third compliance year due to the completion of CEMS installation and certification for most major sources. The emissions reported by CEMS are more accurate than emission factors used by facilities during the first compliance year or the missing data procedures used by many facilities during the second compliance year. Emission factors and missing data procedures tend to rely on conservative estimates or worst-case assumptions which could have overstated the emissions in the first two compliance years.

Refineries implemented emission reduction projects prior to 2001, however, in general emission reductions leveled off over the past 20 years[3].

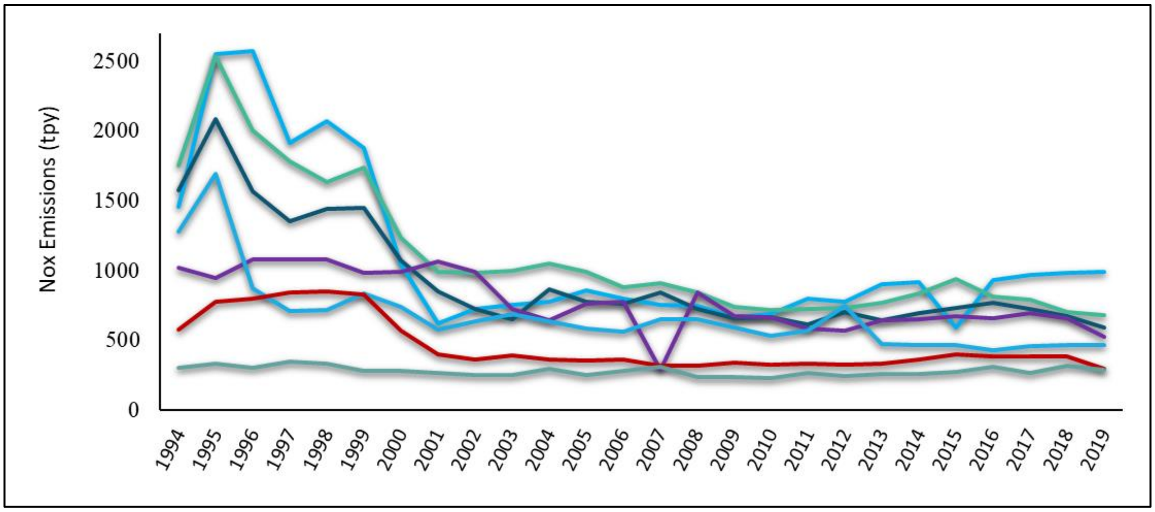


Figure 3. Trend of Annual NOx Emissions from Major Refineries

2016 Air Quality Management Plan (2016 AQMP)

The 2016 AQMP includes control measure CMB-05 which committed to identifying the approaches to make the RECLAIM program more effective. During the adoption of the 2016 AQMP, the Board approved a Resolution that directed staff to "modify the 2016 AQMP NOx measure (CMB-05) to achieve the five tons per day of NOx emission reduction commitment as soon as feasible, and no later than 2025, and to transition the RECLAIM program to a command-and-control regulatory structure requiring BARCT level controls as soon as practicable." To facilitate the transition of facilities from RECLAIM to a command-and-control regulatory structure, a "landing rule" is needed for each unit in RECLAIM. PR 1109.1 is one of fourteen landing rules that is needed for the RECLAIM transition and is in part implementing CMB-05.

AB 617: Nonvehicular Air Pollution – Criteria Air Pollutants and Toxic Air Contaminants

The adoption of AB 617 on July 26, 2017 by the California Legislature addressed facilities that are in cap-and-trade program and subject to the requirements of AB 617. Requirements include an expedited schedule for implementing BARCT for cap-and-trade facilities and a requirement for the Air Districts throughout California to adopt an expedited BARCT schedule by January 1, 2019 to implement BARCT no later than December 31, 2023 by assigning the highest priority to those permitted units that have not modified emissions related permit conditions for the greatest period of time. AB 617 requirements shall not apply to a unit that has implemented BARCT due to a permit revision or a new permit issuance since 2007.

PROPOSED RULE 1109.1

PR 1109.1 is necessary to achieve NOx reductions for the region to meet the state and federal air quality standards. Based on 2017 emissions data, staff estimates approximately 220 units are currently not operating at levels representative of BARCT. Potential NOx emission reductions from implementation of PR 1109.1 are substantial due to the size of the equipment, and the number

[3] http://www.aqmd.gov/docs/default-source/reclaim/reclaim-annual-report/1995-reclaim-report.pdf?sfvrsn=8

and magnitude of units operating above proposed BARCT levels. PR 1109.1 will in part implement CMB-05 by establishing NOx and CO limits that represent BARCT for combustion equipment at petroleum refineries and related facilities and will comply with AB 617 through implementing BARCT at facilities currently in the RECLAIM program. Under RECLAIM, facilities have the option to reduce emissions or to purchase RTCs to meet the annual compliance obligation to ensure that they hold RTCs equal to or greater than their emissions. PR 1109.1 facilities tend to purchase RTCs as their primary compliance option under RECLAIM and are currently holding 55 percent of the RTCs in the RECLAIM program. PR 1109.1 is a command-and-control rule that will require all units to meet NOx concentration limits either directly or in the aggregate.

Third Party Consultants

Staff contracted with two engineering consultants in May 2019: Fossil Energy Research Corporation (FERCo) and Norton Engineering Consultants Inc. (NEC) to provide technical review and input regarding the proposed BARCT NOx emission limits, cost estimates provided by refineries, and staff's approach and methodology to estimate costs where cost from refineries were not provided. Both consultants presented their findings and recommendations at the Working Group Meeting #16 and summarized their findings and recommendations in written reports which are included in Appendices B through G of this staff report.

Fossil Energy Research Corporation (FERCo)

FERCo has extensive knowledge and understanding of SCR as the predominate form of NOx control technology implemented at the local refineries. FERCo has a team of engineers that have robust experience in designing, engineering, and optimizing SCR systems in conjunction with vendors that have performed work for the local refineries. FERCo's design and engineering experience helped to evaluate site-specific issues at each facility. FERCo's engineering strength is also in SCR system optimization which qualifies this team to perform an analysis of existing SCR systems to determine whether further reductions can be achieved.

The FERCo contract was primarily to address the space constraints and challenges specific to petroleum refineries when installing NOx control equipment, in particular SCR installations. FERCo also assisted staff with the cost assessment. Staff and FERCo conducted several facility site visits to assess the availability of space for installation of NOx controls and discuss potential BARCT issues and concerns.

FERCo's statement of work (SOW) describes the tasks to include as follows:

- Perform site visits and engineering evaluation of the affected equipment (including, but not limited to, feasibility of installation of new controls or equipment);
- Consider any challenges associated with installation of control technologies, such as space constraints;
- Review installation challenges at multiple facilities and provide engineering design options when appropriate; and
- Conduct a feasibility study to determine if further optimization can be performed on currently installed NOx control systems to help achieve further reductions.

Norton Engineering Consultants Inc. (NEC)

Norton Engineering has a team of qualified engineers with technical experience in NOx control technologies and BARCT experience with refinery applications. Norton Engineering was contracted to review and conduct an independent review of staff's BARCT assessment. Staff relied on Norton Engineering to address technical questions and to provide their expertise on control technology and combustion equipment.

Norton Engineering's SOW describes the tasks to include as follows:

- Perform a technical feasibility assessment, including a review of commercially viable NOx control technologies and emission reduction levels that each technology can achieve, and any caveats associated with achieving the NOx reductions;
- Evaluate potential emissions of other air pollutants, including PM, ammonia, and CO, when implementing BARCT;
- Review and verify the initial costs that were submitted in 2018; and
- Analyze the modification and use of U.S. EPA SCR cost model, model input assumptions, local labor costs, and other factors that affect the cost-effectiveness calculation.

In March 2021, refineries submitted revised cost estimates. Staff extended the contract with Norton Engineering to provide a third-party review of the revised cost data submitted by refineries.

OTHER RELATED RULEMAKING

The figure below shows the other rule developments that will be required in conjunction with, or to support, PR 1109.1.

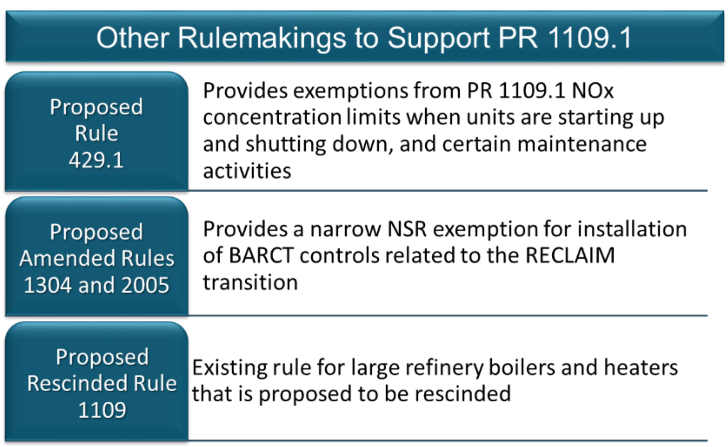


Figure 4. Other Related Rulemaking

Staff is proposing to rescind Rule 1109 when PR 1109.1 is considered for adoption. Since the adoption of RECLAIM, no facilities have been subject to Rule 1109. Proposed Amended Rule 1304 – Exemptions (PAR 1304) and Proposed Amended Rule 2005 – New Source Review for RECLAIM (PAR 2005) will implement a narrow (Best Available Control Technology) BACT exemption for PM and SOx emission increases associated with add-on air pollution control equipment installations or modifications at a RECLAIM or former RECLAIM facility to comply with a BARCT NOx standard. Lastly, Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations (PR 429.1) will exempt equipment from the NOx and CO limits during period when the unit is starting up, shutting down, during certain ~~catalyst~~ maintenance activities, and commissioning, and limit the duration and frequency of ~~those events~~ startups and shutdowns for refineries and associated facilities that are subject to PR 1109.1. PR

429.1, and PARs 1304 and 2005 do not require any additional emission controls. For more information on PAR 1304, PAR 2005, and PR 429.1 please refer to the South Coast AQMD's website under Proposed Rules. Staff is also preparing Draft Staff Reports for these rulemakings that includes additional details regarding the proposals.

PUBLIC PROCESS

PR 1109.1 was developed through a public process that included a series of Working Group Meetings and one community meeting in the AB 617 community of Carson, Wilmington, and West Long Beach. Table 1-2 summarizes the Working Group Meetings held throughout the development of PR 1109.1 and provides a summary of the key topics discussed at each of the Working Group Meetings. Working Group Meetings ranged from one to five hours and included detailed presentations, which are posted on the South Coast AQMD's website[4]. Table 1-3 provides a summary of additional PR 1109.1 meetings.

Staff began the rule development process in the first quarter of 2018 and has conducted 24 Working Group Meetings to date. Staff will continue to conduct Working Group Meetings as well as individual stakeholder meetings as needed. The Working Group is composed of affected facilities, the Western States Petroleum Association (WSPA), consultants, equipment vendors, environmental and community groups, and other agencies such as the California Air Resources Board (CARB) and the U.S. EPA. The purpose of the Working Group Meetings is to work through the development of the proposed rule, discuss proposed rule concepts and identify and address key issues. The focal point of many of the Working Group Meetings was the BARCT assessment and the development of the proposed NOx limits for PR 1109.1. As a result of the impacts of COVID-19 and in accordance with the Governor's Executive Order N-29-20, all Working Group Meetings after March 18, 2020 were conducted remotely via video conferencing and teleconferencing.

Prior to the release of this Draft Staff Report and Draft Rule, seven versions of the draft proposed rule language were released to the public between October 2020 and October 2021. The initial version of the proposed rule language was released on October 23, 2020; the subsequent version released on November 20, 2020 included a subdivision with the alternative compliance options. A revised draft was released on December 24, 2020. One additional draft was released prior to the preliminary draft package, the pre-preliminary draft rule language version was released on July 21, 2021. The preliminary draft package was released on August 20, 2021 as part of the 75-day noticing of the Public Workshop, and two subsequent pre-30-day draft versions of the rule language were released on September 24, 2021 and October 4, 2021.

[4] http://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book/proposed-rules/proposed-rule-1109-1

Table 1-2. Summary of Working Group Meetings and Released Documents

Date	Meeting Title	Highlights
February 21,2018	Working Group Meeting #1	• Rule background • Potential universe • Equipment types and NOx emissions
June 14, 2018	Working Group Meeting #2	• Provided update on the survey questionnaire status (distribution, meeting with stakeholders, and revisions) • Revised universe and equipment • BARCT legal requirements and assessment approach • Emission data evaluation for all equipment categories
August 1, 2018	Working Group Meeting #3	• Progress of rule development • WSPA comments • First three steps of BARCT technology assessment
September 12, 2018	Working Group Meeting #4	• Presented the results from the fourth step of the technology assessment – "Assessment of Pollution Control Technology" for PR 1109.1 equipment • Presented emerging NOx control technologies • Control technologies and potential reductions
November 28, 2018	Working Group Meeting #5	• Analysis of the survey data submitted by the stakeholders • Methodology for data analysis for each of the seven source equipment categories • Low NOx burner/ultra-low NOx burner technologies
January 31, 2019	Working Group Meeting #6	• Updates and revisions to the survey data • Update on the Request for Proposal • Key takeaways from meetings with control technology vendors
April 30, 2019	Working Group Meeting #7	• NOx control technologies from meetings with manufacturers • BACT requirements due to equipment retrofit or replacement • U.S. EPA SCR Cost Model
June 27, 2019	Working Group Meeting #8	• Update on contracts with third-party consultants • CEMS data analysis • Methodology to determine operational peak • Modification to the U.S. EPA SCR Cost Model
December 12, 2019	Working Group Meeting #9	• NOx emission baseline • U.S. EPA SCR Cost Model modified with stakeholder costs • BARCT recommendations for the heaters and boilers • John Zink Combustions presented their new SOLEX burner technology for refinery heaters

Date	Meeting Title	Highlights
February 18, 2020	Working Group Meeting #10	• ClearSign Core^{TM} burner project • Revised cost-effectiveness assessment for boilers and heaters • BARCT NOx limits for gas turbines, FCCUs, and SRU/TG incinerators • Internal combustion engines (ICEs) applicability in rule
Transitioned to Remote Participation via Zoom Video Conference Due to COVID-19		
May 21, 2020	Working Group Meeting #11	• Proposed BARCT NOx limits for the SMR heaters and ICEs • Proposed averaging times for boilers, process heaters, SMR heaters, gas turbines, FCCUs, SRU/TG Incinerators, and auxiliary ICEs
July 17, 2020	Working Group Meeting #12	• Follow-up on proposed BARCT NOx limits for ICEs • Proposed BARCT NOx limits for coke calciners and vapor incinerators • Response to the WSPA comment letter
August 12, 2020	Working Group Meeting #13	• Follow-up on SMR heaters BARCT assessment • BARCT NOx assessment for sulfuric acid plants (furnaces and startup heaters and boilers) • BARCT Evaluation of heaters and boilers with existing SCRs • Co-pollutants and sulfur clean-up in refinery fuel gas • Rule implementation concepts
August 27, 2020	Working Group Meeting #14 – Community Meeting with impacted communities of Carson, Wilmington, and West Long Beach	• Proposed BARCT NOx limits • Projected NOx emission reductions • Concepts for rule implementation • Request for equipment information for each refinery and the anticipated control technology by community representatives
October 23, 2020		Released First Version of PR 1109.1 Rule Language
November 4, 2020	Working Group Meeting #15	• Response to stakeholders' comments including updates to the BARCT assessments and rule language concepts • Rule implementation concept, BARCT-Compliance Alternative Plan (B-CAP)
November 20, 2020		Released Second Version of PR 1109.1 Rule Language with the B-Cap subdivision included

Date	Meeting Title	Highlights
December 10, 2020	Working Group Meeting #16 – Consultants presented Final Reports	• Revisions to CO and CEMS requirements • Updates to the implementation schedule • FERCo and Norton Engineering presentations • Revisions to PR 1109.1 based on feedback from FERCo and Norton Engineering
December 24, 2020		Released Third Version of PR 1109.1 Rule Language
February 4, 2021	Working Group Meeting #17	• Multiple SCR reactors • Rule language updates • Presentation by ClearSign™
February 11, 2021	Working Group Meeting #18	• Other related rulemaking projects • New approaches to achieve BARCT for large boilers and heaters • Review of BARCT and incremental cost-effectiveness assessments • Responses to submitted comment letters
March 4, 2021	Working Group Meeting #19	• Request for revised cost data • Proposed an updated NOx limit for large boilers and heaters (≥ 40 MMBtu/hr) • Reconsideration of FCCU and Vapor Incinerator BARCT assessment • Revised implementation schedule and approach with considerations for turnaround schedules • Introduced BARCT Equivalent Compliance Plan (B-Plan)
April 30, 2021	Working Group Meeting #20	• BARCT implementation and compliance plans • Proposed Rule 429.1 for startup and shutdown provisions at petroleum refineries • Presentation by ClearSign™ about combustion update
May 27, 2021	Working Group Meeting #21	• Introducing Bridge Concepts • Response to stakeholder's comment letters • Incremental Cost-Effectiveness Assessment • Alternative I-Plan Concepts • Gas Turbine and SMR Heater follow up
June 30, 2021	Working Group Meeting #22	• WSPA proposal and staff response • Facility provided updated costs and staff analysis • BARCT reassessment for large boilers and heaters and FCCUs • Initial concepts for mass emissions approach which was the revised B-Cap
July 14, 2021	Working Group Meeting #23	• Bridge limit considerations • PM/Co pollutant discussion

Date	Meeting Title	Highlights
		• BARCT reassessment for Vapor Incinerators • BARCT Equivalent Mass Cap (B-Cap) considerations
July 21, 2021		Fourth Version of PR 1109.1 Rule Language
July 28, 2021	Working Group Meeting #24	• BARCT reassessment for Vapor Incinerators • Discussion of July 21 version of Proposed Rule 1109.1
August 20, 2021		Release Preliminary Draft Rule and Staff Report
September 15, 2021	Working Group Meeting #25	• Discussed proposed changes to PR 1109.1, PR 429.1, and PAR 1304 • Discussed key issues
September 24, 2021		Release Pre-30-day Draft Rule
October 4, 2021		Release Revised Pre-30-day Draft Rule
October 6, 2021		Release Draft Rule and Staff Report

Table 1-3. Summary of Other Meetings

Date	Meeting Title
September 18, 2020	Stationary Source Committee Update
November 3, 2020 – November 6, 2020	CEQA meeting with all 16 Facilities
January 13, 2021 – September 24, 2021	Multiple B-Plan and I-Plan Meetings with all the 5 major petroleum refineries and the Environmental and Community Groups
February 19, 2021	Stationary Source Committee Update
March 19, 2021	Stationary Source Committee Update
June 18, 2021	Stationary Source Committee Update
September 1, 2021	Public Workshop
September 10, 2021	Study Session
September 17, 2021	Stationary Source Committee Update
October 1, 2021	Set Hearing
October 26, 2021	Community Meeting

* Reference to B-CAP was changed later to the "B-Plan." In June staff introduced a new concept that was again referred to as a "B-Cap."

Throughout the rulemaking, staff has been meeting with individual stakeholders. In January 2021 staff initiated individual meetings with the five major petroleum refineries and environmental and community groups. Since January 2021, staff has held over 50 meetings with Chevron, Marathon (Tesoro Refinery), Phillips 66, Torrance Refining, and Valero. Since February 2021, staff held 15 meetings and met with representatives of Earth Justice, Coalition for Clean Air, Natural Resources Defense Council, and Communities for a Better Environment. In May 2021 after the WSPA proposed an alternative approach to PR 1109.1, staff began meeting weekly with WSPA and held ten meetings beginning May 20, 2021. Staff also met periodically, but on a less frequent basis with AltAir, World Oil, and Eco Services.

CHAPTER 2 BARCT ASSESSMENT

INTRODUCTION

Affected Facilities

PR 1109.1 will affect 16 facilities, including nine petroleum refineries, three small refineries, and four facilities with related operations.

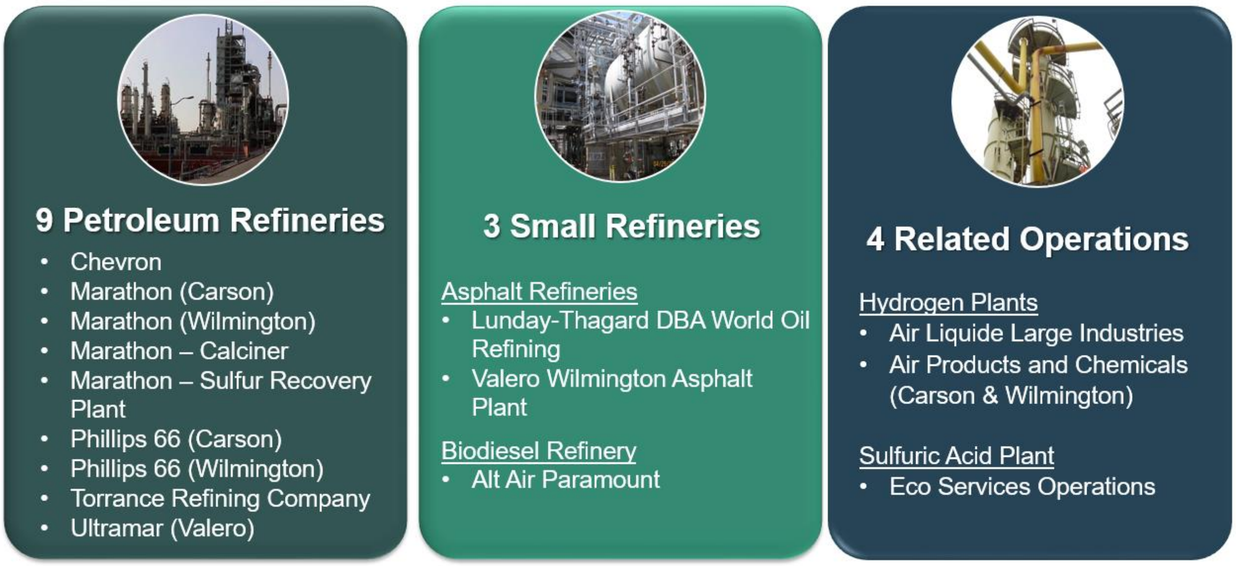


Figure 5. PR 1109.1 Affected Facilities

PR 1109.1 will be applicable to 16 out of the 246 facilities in the NOx RECLAIM program as of October 2020; however, based on the 2017 RECLAIM Annual Emission Reports, these 16 facilities are responsible for 12.4 out of 19.9 tons per day of the NOx emissions.

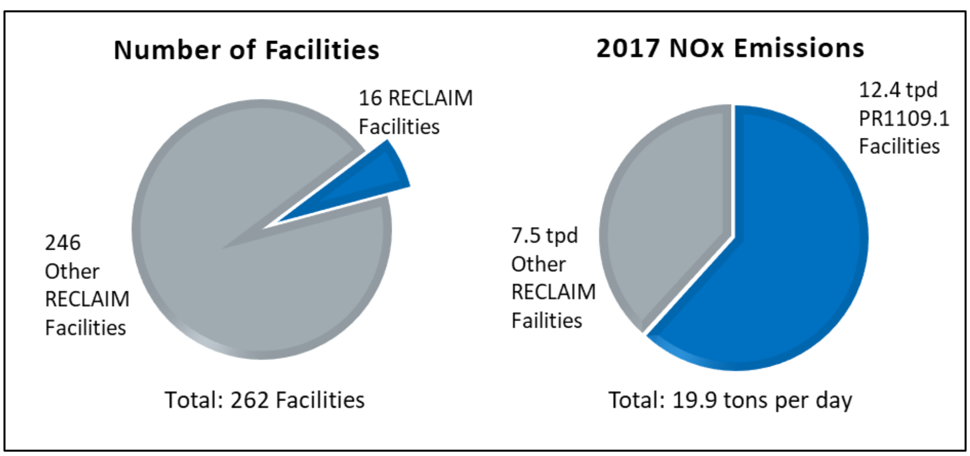


Figure 6. Number of Facilities and NOx Emissions PR 1109.1 versus RECLAIM

Affected Equipment

PR 1109.1 applies to nearly all combustion equipment at petroleum refineries and related facilities. Based on South Coast AQMD's permit database and facility surveys, staff has identified 284 units that will be subject to the PR 1109.1, with six major categories of equipment:

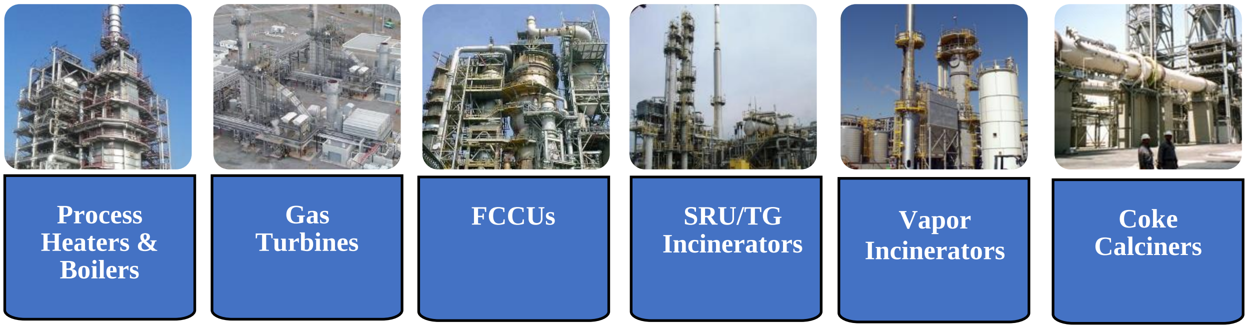


Figure 7. Major Categories of Equipment

Heaters and boilers are the largest equipment categories representing 80 percent of all equipment. There are many subcategories of equipment, especially in the process heater and boiler category which includes steam methane reformer (SMR) heaters, sulfuric acid plant furnaces, and startup heaters or boilers. The vapor incinerator category also includes several subsets including soil vapor extraction units, thermal oxidizers, and one small flare.

The table below summarizes the number of PR 1109.1 equipment at the 16 refineries and related facilities.

Table 2-1. PR 1109.1 Affected Equipment by Facility

	Process Heater/ SMR Heater/ Boiler	SRU/TG Incinerator	Vapor Incinerator	Gas Turbine	Start-Up Heater/ Boiler	FCCU	Coke Calciner	Flare
Tesoro-Carson	30	2	0	4	1	1	0	0
Tesoro-Wilmington	33	0	0	2	0	0	0	0
Tesoro-Sulfur Recovery Plant	0	2	0	0	0	0	0	0
Tesoro-Coke Calciner	0	0	0	0	0	0	1	0
Torrance	28	2	2	0	1	1	0	0
Chevron	37	4	5	4	1	1	0	0
P66-Carson	10	2	0	0	0	0	0	0
P66-Wilmington	34	2	0	1	2	1	0	0
Ultramar	19	1	0	1	1	1	0	0
AltAir	25	1	4	0	0	0	0	0
Lunday Thagard	5	0	2	0	0	0	0	0
Air Products-Carson	1	0	0	0	0	0	0	0
Air Products-Wilmington	1	0	0	0	0	0	0	0
Air Liquide	1	0	0	0	0	0	0	0
Eco-Services	0	0	0	0	2	0	0	1
Valero Asphalt Plant	4	0	0	0	0	0	0	0
Total	**228**	**16**	**13**	**12**	**8**	**5**	**1**	**1**

There are three source categories of combustion equipment at petroleum refineries and related facilities that are not included in PR 1109.1: refinery flares, small heaters used for comfort heating, and internal combustion engines (ICEs). These categories are regulated under existing South Coast AQMD rules. Details of exclusion are provided in the following sections for each category.

Refinery Flares

Refinery flares that are used exclusively to burn excess hydrocarbon gases are excluded from RECLAIM and will also be excluded from PR 1109.1. Those flares are currently regulated under Rule 1118 – Control of Emissions from Refinery Flares. Two types of flares are generally operated at refineries: elevated flares and flares, usually defined by the height of the flare tip above ground.

However, there is a small flare used at one of the facilities with related operation to petroleum refineries for plant activities such as tank degassing and truck unloading that is subject to PR 1109.1. The BARCT assessment for that unit is discussed later in this chapter and in Appendix G.

Small Heaters

Refinery boilers and heaters used in the petroleum refining process are all greater than 2 MMBtu per hour. Small heaters (less than or equal to 2 MMBtu per hour) used for comfort heating that are not used in refinery processing operations, are not subject to PR 1109.1. Small natural gas-fired water heaters, boilers, and process heaters (less than or equal to 2 MMBtu/hr) at PR 1109.1 facilities will be regulated under Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters (Rule 1146.2). Units regulated under Rule 1146.2 are small and generally used for large water heaters and do not include units within the operating process of the refinery.

Internal Combustion Engines

There are three diesel ICEs at facilities within the PR 1109.1 universe that are used to power gas turbines during startup only. All these ICEs are low-use (less than 13 hours per year) engines with NOx emissions less than 0.001 ton per day. A BARCT assessment for these units was conducted and presented during the Working Group Meeting #11 held on May 21, 2020 and a follow-up assessment was presented during Working Group Meeting #12 held on July 17, 2020. SCR was determined to be the best retrofit control technology to reduce NOx; however, because these ICEs are only used for short time periods during the start-up of gas turbines, they would not reach the minimal temperature required for the SCR to reduce NOx. Staff evaluated ICE replacement to achieve significant NOx reductions. Based on the NOx limits in Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines (Rule 1110.2), staff evaluated an 11 ppmv NOx limit, as required for stationary ICE, as well as a 36 ppmv NOx limit, as allowed for low-use ICE (less than 500 hours/year). The BARCT assessment demonstrated that meeting a NOx emission limit of 11 ppmv or 36 ppmv was not cost-effective and would have technical challenges. Staff considered including a low-use exemption in PR 1109.1 (i.e., operating for ≤100 hours per year) and establishing NOx limits and requirements if the unit exceeds the annual operating hour exemption. However, staff determined the best path forward for these low-use ICEs was to allow them to be subject to Rule 1110.2 which has a provision under subparagraph (i)(1)(E) for auxiliary engines used to power other engines or gas turbines during startups.

BARCT ASSESSMENT APPROACH

The purpose of a BARCT assessment is to assess available pollution controls to establish emission limits for specific equipment categories consistent with the state law. Under California Health and Safety Code Section 40406, BARCT is defined as:

> "an emission limitation that is based on the maximum degree of reduction achievable by each class or category of source, taking into account environmental, energy, and economic impacts."

The BARCT assessment follows a framework through the rule development process and includes public participation. The figure below shows the BARCT assessment approach. A summary of the BARCT assessment is provided in this chapter. A complete BARCT assessment for each class or category is presented in Appendices B through G.

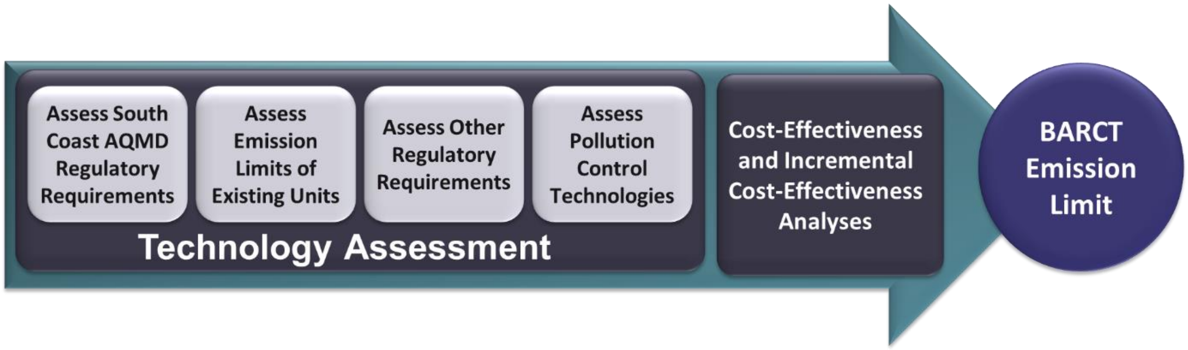


Figure 8. BARCT Assessment Approach

The scope of BARCT including Retrofit Versus Replacement, Emerging Technology, and Class and Category Determination

During the rule development of command-and-control rules for the RECLAIM transition, industry stakeholders commented on the scope of "best available retrofit control technology" relative to Health & Safety Code § 40440(b)(1). A commenter stated that the use of the word "retrofit" precludes the South Coast AQMD from requiring emissions limits that can only be cost-effectively met by replacing the basic equipment with new equipment. Staff believes that the use of the term "retrofit" does not preclude replacement technology.

The on-line Merriam-Webster Dictionary defines "retrofit" in a manner that does not preclude replacing equipment. That dictionary establishes the following definition for retrofit: "1) to furnish (something, such as a computer, airplane, or building) with new or modified parts or equipment not available or considered necessary at the time of manufacture, 2) to install (new or modified parts or equipment) in something previously manufactured or constructed, 3) to adapt to a new purpose or need: modify." https://www.merriam-webster.com/dictionary/retrofit. This definition does not preclude the use of replacement parts as a retrofit.

The on-line Dictionary.com is more explicit in allowing replacement parts. It includes the following definitions for retrofit as a verb: "1. to modify equipment (in airplanes, automobiles, a factory, etc.) that is already in service using parts developed or made available after the time of original manufacture, 2. to install, fit, or adapt (a device or system) or use with something older; to retrofit solar heating to a poorly insulated house, 3. (of new or modified parts, equipment, etc.) to fit into or onto existing equipment, 4. to replace existing parts, equipment, etc., with updated parts or systems." http://www.dictionary.com/browse/retrofit. This definition clearly includes replacement of existing equipment within the concept of "retrofit." Accordingly, the use of the term "retrofit" can include the concept of replacing existing equipment.

Moreover, the statutory definition of "best available retrofit control technology" does not preclude replacing existing equipment with new cleaner equipment. Health & Safety Code § 40406 provides: "As used in this chapter, 'best available retrofit control technology' means an emission limitation that is based on the maximum degree of emission reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source." Thus, BARCT is an emissions limitation, and is not limited to a particular technology, whether add-on or replacement. Certainly, this definition does not preclude replacement technologies.

Staff also notes that the argument precluding replacement equipment would have an effect contrary to the purposes of BARCT. For example, staff has proposed, and the Board adopted in Rule 1135 a BARCT that may be more cost-effectively be met for diesel-fueled engines by replacing the engine with a new Tier IV diesel engine rather than installing additional add-on controls on the current engine which may be many decades old. If the South Coast AQMD were precluded from setting BARCT for these sources, the oldest and dirtiest equipment could continue operating for possibly many more years, even though it would be cost-effective and otherwise reasonable to replace those engines. There is no policy reason for insisting that replacement equipment cannot be an element of BARCT as long as it meets the requirements of the statute including cost-effectiveness.

The case law supports an expansive reading of BARCT. In explaining the meaning of BARCT, the California Supreme Court held that BARCT is a "technology-forcing standard designed to compel the development of new technologies to meet public health goals." (*American Coatings Ass'n. v. South Coast Air Quality Mgt. Dist.,* 54 Cal. 4th 446, 465, 2012). In fact, the BARCT requirement was placed in state law for the South Coast AQMD in order to "encourage more aggressive improvements in air quality" and was designed to augment rather than restrain the South Coast AQMD's regulatory power (*American Coatings*, *supra*, 54 Cal. 4th 446, 466). Accordingly, BARCT may actually be more stringent than BACT, because BACT must be implemented today by a source receiving a permit today, whereas BARCT may, if so, specified by the South Coast AQMD, be implemented a number of years in the future after technology has been further developed (*American Coatings, supra,* 54 Cal. 4th 446, 467).

The Supreme Court further held that when challenging the South Coast AQMD's determination of the scope of a "class or category of source" to which a BARCT standard applies, the challenger must show that the South Coast AQMD's determination is "arbitrary, capricious, or irrational." (*American Coatings, supra,* 54 Cal. 4th 446, 474). Therefore, the South Coast AQMD may consider a variety of factors in determining which sources must meet specific BARCT emissions level. If, for example, some sources could not cost-effectively reduce their emissions further because their emissions are already low, these sources can be excluded from the category of sources that must meet a particular BACT. Therefore, the South Coast AQMD may establish a BARCT emissions level that can cost-effectively be met by replacing existing equipment rather than installing add-on controls, and the South Coast AQMD's definition of the category of sources which must meet a particular BARCT is within the South Coast AQMD's discretion as long as it is not arbitrary or irrational.

Emerging Technology

The BARCT emission levels can also be technology forcing NOx concentration limits, meaning the limits can be based on emerging technology provided the NOx limit is achievable by the compliance date. Emerging technology is technology that can achieve emission reductions but is not widely available at the time the NOx limit is established and the rule is adopted. When South Coast AQMD adopts rules with technology forcing emission limits, the limits are given a future implementation date to allow time for the technology to develop. BARCT limits evolve over time as technology improves or new pollution control technologies emerge; setting future effective emission limits is appropriate and the approach has been used, and upheld, in other rules. South Coast AQMD adopted volatile organic compound (VOC) limits in Rule 1113 – Architectural Coatings in 2002 with a future effective date of July 1, 2006, based on emerging technology (e.g., reformulated coatings). The technology to meet the lower VOC limits was commercially available but had performance issues that had yet to be overcome. The American Coatings Association sued the South Coast AQMD for adopting technology forcing BARCT limits, but the South Coast

AQMD prevailed in the Supreme Court of California upholding the ability to adopt technology forcing BARCT limits.

Class and Category of Equipment

One of the first steps in the BARCT assessment is to establish the class and category of equipment. Staff collaborated with the stakeholders to establish the class and category by accounting for the type of equipment, size, fuel type, and other unique operational features of the units. The following table lists the initial class and category of equipment established for the BARCT assessment of the equipment subject to PR 1109.1. Based on the BARCT technology assessment, the only category that has been distinguished by fuel type is the Gas Turbine category and the fuel type is included in the table for other categories for informational purposes. Renewable fuel gas listed in the following table is the gas generated at a biofuel plant.

Table 2-2. Class and Category of Equipment

Equipment Category	Size (MMBtu/hour)	Fuel Type
Boilers	<20	Refinery Fuel Gas, Natural Gas
	≥20 – <40	
	≥40 – ≤110	
	>110	
Flares	All	Natural Gas
FCCUs	All	Coke Burn-Off
FCCU Startup Heaters	All	Refinery Fuel Gas, Natural Gas, Ultra-Low-Sulfur Diesel
Gas Turbines Fueled with Natural Gas	All	Natural Gas
Gas Turbines Fueled with Gaseous Fuel other than Natural Gas	All	Refinery Fuel Gas, Other Process Gas, Propane, Butane, Other Gaseous Fuels
Petroleum Coke Calciners	All	Natural Gas
Process Heaters	<20	Refinery Fuel Gas, Natural Gas, Renewable Fuel Gas
	≥20 – <40	
	≥40 – ≤110	
	>110	
SRU/TG Incinerators	All	Refinery Fuel Gas, Natural Gas, Tail Gas, Renewable Fuel Gas
SMR Heaters	All	PSA-Off Gas, Refinery Fuel Gas, Natural Gas
SMR Heaters with Gas Turbine	All	PSA-Off Gas, Natural Gas
Sulfuric Acid Furnaces	All	Refinery Fuel Gas, Natural Gas, Hydrogen Sulfide
Sulfuric Acid Startup Heaters	All	Natural Gas
Sulfuric Acid Startup Boilers	All	Natural Gas
Vapor Incinerators	All	Refinery Fuel Gas, Natural Gas, Renewable Fuel Gas

Technology Assessment

Staff conducted a thorough technology assessment to evaluate the NOx control technologies that will achieve the BARCT level for combustion equipment at petroleum refineries and facilities with related operations to petroleum refineries subject to PR 1109.1. The technology assessment consists of four steps including the assessment of South Coast AQMD requirements, a complete assessment of emission limits of existing units, review of other regulatory requirements, and assessment of available pollution control technologies.

Assess South Coast AQMD Regulatory Requirements

Assessment of South Coast AQMD Regulatory Requirements

Staff reviewed existing South Coast AQMD NOx regulations from combustion equipment at petroleum refineries and facilities with related operations. The combustion equipment within the refining sector consists of six main source categories previously discussed (see Figure 2-3). In addition, staff evaluated the South Coast AQMD NOx regulations for combustion equipment in non-refinery settings to assess potential technology transfer. This includes the evaluation of rules and regulations affecting equipment categories that will be regulated under PR 1109.1 (e.g., boilers and process heaters). The technology assessment includes a review of existing South Coast AQMD regulations to determine if NOx limits have been established for similar types of equipment that should be considered for PR 1109.1. In addition to the NOx rules, staff also evaluated the BARCT assessments which were previously conducted in 2005 and 2015 as part of the RECLAIM program to reduce facility's allocations. The following table summarizes the South Coast AQMD NOx rules that staff evaluated as part of the BARCT technology assessment.

Table 2-3. South Coast AQMD Regulatory Requirements

Regulation/Rule Title	Relevant Unit/Equipment	Fuel Type
RECLAIM BARCT (2005)	Refinery Boilers and Process Heaters, Petroleum Coke Calciners, FCCUs, Gas Turbines	See Table 2-2
RECLAIM BARCT (2015)	Refinery Boilers and Process Heaters, Petroleum Coke Calciners, FCCUs, Gas Turbines, SRU/TG Incinerators	See Table 2-2
Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines	Stationary and Portable Engines	Gaseous Fuels, Liquid Fuels
Rule 1118.1 – Control of Emissions from Non-Refinery Flares	Non-Refinery Flares	Landfill Gas, Digester Gas, Process Gas, VOC Off-Gas
Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines	Gas Turbines	Gaseous Fuels, Liquid Fuels
Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional and Commercial Boilers, Steam Generators, and Process Heaters	Boilers and Process Heaters	Gaseous Fuels, Non-Gaseous Fuels, Landfill Gas, Digester Gas
Rule 1147 – NOx Reductions from Miscellaneous Sources	Incinerators, Afterburners, Remediation Units, Thermal Oxidizers, Calciners/Kilns	Gaseous Fuels, Liquid Fuels

Assessment of Emission Limits of Existing Units

This step of the BARCT assessment highlights the emissions levels that can be achieved for the existing units in the different categories of equipment. To conduct this assessment, staff evaluated the current emissions and NOx concentrations of the existing units in the PR 1109.1 universe. Data on existing units include South Coast AQMD data such as permit limits, source test data, CEMS, and annual emission reports as well as the comprehensive data which staff received through the facility surveys. Summaries of the emission levels being achieved on equipment for each class and category in the PR 1109.1 universe are included later in this chapter, with detailed information discussed later in the appendices.

Other Regulatory Requirements

The next step of the technology assessment is to identify other agencies that regulate the same or similar equipment and compare the regulatory requirements and emissions limits. The purpose of this step is to evaluate if there are applicable emissions limits that should be considered. The table below includes the list of regulations by other agencies which staff reviewed for applicable emissions limits. The specific emission limits and their impact on the BARCT assessment is included for each class and category discussed in the appendices for each of the equipment categories.

Table 2-4. Other Regulatory Requirements

Regulatory Entity	Regulation/Rule Title	Relevant Units/Equipment
Bay Area Air Quality Management District	Regulation 9-10-301 – Refinery-Wide NOx limit for boilers, steam generators and process heaters, excluding CO Boilers	Heater and Boiler
	Regulation 9-10-307 – Refinery NOx Emission Limit for CO Boilers	FCCU
	Regulation 9, Rule 9 - Limits Emissions of NOx from Stationary Gas Turbines	Gas Turbine
San Joaquin Valley Air Pollution Control District	Rule 4306 – Boiler, Steam Generators, and Process Heaters – Phase 3	Heater and Boiler
	Rule 4320 – Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr	Heater and Boiler
	Rule 4311 – Flares	Flare and Thermal Oxidizer
	Rule 4313 – Lime Kilns	Petroleum Coke Calciner
Texas Commission on Environmental Quality	Title 30, Part 1, Chapter 117, Subchapter B, Division 3, Rule §117.310 – Emission Specifications for Attainment Demonstration	Petroleum Coke Calciner
		FCCU
		Gas Turbine
		SRU/TG Incinerator

Assess Pollution Control Technologies

Assessment of Pollution Control Technologies

The next step is to research the commercially available emission control technologies and seek information on any emerging emission control technologies. As part of this assessment, staff met with multiple air pollution control vendors who have experience working with petroleum refineries and related industries to discuss NOx emissions control technologies. Staff also invited several vendors to present at the Working Group Meetings to address the stakeholders' concerns regarding the available and applicable technologies for the purpose of NOx emissions reduction. Staff also relied on the third-party consultants who also reached out to the technology vendors and had discussions on the level of emission controls that can be achieved with the state-of-the-art technology. Appendix A has descriptions for the NOx control technologies, emission reduction performance, and the applicable units they can control; the following section contains an overview of the control technologies staff evaluated.

Table 2-5. Technology Vendors

Vendor	Control Equipment
CECO Peerless	SCR and AIG systems
Zeeco	LNBs and ULNBs
Cormetech	SCR catalyst options
Umicore	SCR catalyst options
John Zink Hamworthy	LNB, ULNB, SOLEX™ burners, and SCR Systems
ClearSign™	Duplex™ Technology

Table 2-6. Commercially Available NOx Controls per Equipment Category

Technology	Heater	Boiler	FCCU	Coke Calciner	Gas Turbine	SRU/TG Incinerator	Vapor Incinerator
Water/Steam Injection	X	X			X		
Flue Gas Recirculation	X	X			X		
NOx Combustion Additive			X				
Ultra-Low NOx Burners	X	X				X	X
Low NOx Burners	X	X				X	X
Selective Catalytic Reduction	X	X	X	X	X	X	X
LoTOx™ w/ Wet Gas Scrubber	X	X	X	X		X	X
UltraCat™	X		X	X			

The most utilized NOx controls are low- or ultra-low NOx burners and post-combustion controls such as low temperature oxidation process for NOx control (LoTOx™), UltraCat™ catalyst filter manufactured by Tri-Mer Corporation (UltraCat™), and SCR. The table below demonstrates the potential achievable NOx reductions and Appendix A contains detailed descriptions of the control technology.

Table 2-7. NOx Control Technologies, Application, and Performance

NOx Control Technologies	Application	Achievable Performance
LoTOx™ or UltraCat™ or SCR	Petroleum Coke Calciner, FCCUs	~95% Reduction
SCR or ULNB with SCR	Boilers/Process Heaters, Gas Turbines	Greater than 95% Reduction
ULNB	Boilers/Process Heaters fueled by Refinery Fuel Gas	20 – 30 ppmv[(1)] Optimal installation 40 – 50 ppmv[(1)] Sub-Optimal installation
ULNB	SRU/TG Incinerators, Sulfuric Acid Plants, Thermal Oxidizers (operating on refinery fuel, renewable fuel, or natural gas)	20 – 30 ppmv[(1)]
ULNB[(1)]	Boilers fueled by Natural Gas	5 ppmv[(1,2)]

(1) Based on a 3 percent O_2 correction
(2) Rapid Mix™ burner (RMB) from John Zink

In addition to the commercially available technologies, staff evaluated several emerging technologies that are currently not widely available but have demonstrated the potential for emission reductions in the future. The following table summarizes the emerging technologies, and their application and potential NOx reduction.

Table 2-8. Summary of Emerging Technology, Application, and Performance

NOx Control Technologies	Potential Applications	Potential Performance (ppmv at 3% O_2)
ClearSign™	Boilers/Process Heaters	<9
Great Southern Flameless	Process Heaters	<10
Solex™	Process Heaters	<5

The ClearSign™ emerging technology is already being implemented at local facility. The ClearSign Core™ technology operates like a traditional ULNB burner and is a direct burner replacement. There is currently a demonstration project that began March 2021 at World Oil, where ClearSign™ Core burner technology was installed in a heater with a rated heat input capacity of 39 MMBtu/hr equipped with five burners. The unit is currently achieving around 29.3 ppmv and is anticipated to achieve even lower NOx levels once the burners are further optimized. Further discussion on the ClearSign™ Core technology can be found in Appendix A.

PR 1109.1 includes a 9 ppmv NOx limit for process heaters less than 40 MMBtu/hour based on the potential of these emerging technologies. To allow time for the technology to develop, the

9 ppmv limits will not be required until ten years after rule adoption and once 50 percent or more of the burners are replaced or the replaced burners represent 50 percent or more of the heat input of the process heaters.

Initial BARCT Emission Limit and Other Considerations

After completing the technology assessment, staff recommends an initial BARCT NOx emission limit established using information gathered from the technology assessment. All provided emission concentration values (i.e., initial and final) in this report have the unit of part per million volume (ppmv) based on a dry basis. Additionally, staff evaluates other considerations that could affect the emission limits that represent BARCT, including ammonia limits if SCRs are likely to be installed, CO limits, averaging times, and conditional limits for those units operating close to the BARCT NOx limits. In addition, staff evaluates units that are considered outliers due to low-emissions, low-use, or high cost-effectiveness.

Ammonia Emissions

Currently, when post-combustion equipment such as SCR is being permitted, ammonia emissions from ammonia slip are evaluated. Under Regulation XIII – New Source Review (Regulation XIII), the BACT ammonia concentration limit for SCR systems is 5 ppmv. Staff did consider including an ammonia concentration limit in PR1109.1 but believes that this is a Regulation XIII issue and will be best addressed during permitting process. Evaluating the ammonia BACT limit during permitting provides the opportunity for an individual evaluation of the ammonia limit per equipment to ensure that the proposed NOx limit in PR 1109.1 is achieved. Any additional provisions for monitoring ammonia will also not be included in PR 1109.1 but may be required during permitting. When considering technical feasibility and costs of control equipment, staff assumed a 5 ppmv ammonia limit would be applied.

Carbon Monoxide Limits

In addition to NOx limits, PR 1109.1 establishes CO limits in order to maintain CO emissions. The South Coast AQMD region is in attainment for CO but is seeking to prevent any increase in CO emissions, which has the potential to rise when NOx emissions are controlled. The CO limits included in PR 1109.1 reflect limits in existing permits. PR 1109.1 allows operators to retain existing CO permit limit, if it is higher than the proposed CO limit in PR 1109.1; however, facilities with CO limits in their existing permits that are lower than the levels in the proposed rule will be required to maintain those lower CO permit limits.

Averaging Times

Averaging times are another key consideration when establishing the NOx limit. The need for appropriate averaging times was frequently discussed with Norton Engineering during staff's BARCT assessment. Norton Engineering stressed the need for longer averaging times for the facilities to comply with the low-NOx limits being proposed. A more detailed discussion of averaging times for each equipment category is available in Appendix B through Appendix G. Table 2-9 summarizes these averaging times.

Cost-Effectiveness and Incremental Cost-Effectiveness Analyses

Cost-Effectiveness and Incremental Cost-Effectiveness Analyses

Once the technical assessment is complete, staff evaluates the cost-effectiveness of initial BARCT NOx emission limit, or range of potential limits. If the NOx controls that achieved the maximum emission reduction is not cost-effective, the next level of control is evaluated.

Cost-effectiveness is measured in terms of cost of the control method to meet the proposed NOx limit per tons of NOx reduced over the lifetime of the control equipment. The data needed to conduct the cost-effectiveness analysis includes capital and installation costs, operating and maintenance costs, emission reductions, discount rate, and equipment life. If the cost per ton of emissions reduced is within a defined threshold, the control method is considered to be cost-effective.

The South Coast AQMD relies on the Discounted Cash Flow (DCF) method which converts all costs, including initial capital investments and costs expected in the present and future years of equipment life, to a present value. In the interest of transparency and comparability, staff is also providing cost-effectiveness values based on the Levelized Cash Flow (LCF) method in Chapter 4 and Appendix B through Appendix G. The main difference between the DCF and LCF methods lies in how the costs are expressed. DCF utilizes the present value, or a stream of all present and future costs discounted to and summed up in the same initial year. The LCF method annualizes the present value of total costs as if all costs, including the initial capital investments, would be paid off in the future with an equal annual installment over the equipment life. For this reason, a cost-effectiveness value as calculated using DCF is always lower than that calculated using LCF. The current DCF threshold for NOx and SOx was established in 2010 SOx RECLAIM BARCT assessment as $50,000 per ton reduced. The $50,000 per ton of emissions reduced threshold was also used in the 2016 AQMP. If the threshold is inflated to represent current dollars using the Marshall and Swift Index, the current value for DCF threshold would be about $60,000 per ton of emissions reduced.

Incremental Cost Effectiveness Analysis

Finally, California Health and Safety Code Section 40920.6(a)(3) states that an incremental cost-effectiveness assessment should be performed on identified potential control options that meet air quality objectives. To determine the incremental cost-effectiveness under this paragraph, South Coast AQMD calculates the difference in the dollar costs divided by the difference in the emission reduction potentials between each progressively more stringent potential control option as compared to the next less expensive control option. Once the BARCT assessment is complete and NOx limits are established, staff considers incrementally more stringent options to demonstrate that the NOx limit represents the "maximum degree of reduction achievable by each class or category". The incremental cost-effectiveness assessment is presented in Chapter 4.

BARCT Emission Limit

According to California Health and Safety Code Section Sections 40920.6(a)(1) and 40920.6(a)(2), potential controls to meet an air quality objective, which is to assess the BARCT emission limits, must be identified and the cost-effectiveness assessment should be conducted thereafter. The final proposed BARCT emission limit for each class and category is the emission limit that achieves the maximum degree of emission reductions and is determined to be cost-effective. Staff evaluated the cost-effectiveness for the most stringent initial BARCT emission limit. If the most stringent initial BARCT limit is not cost-effective, the next less stringent limit was assessed. The following table summarizes the proposed NOx limits that represent BARCT, the applicable CO limits, and the proposed averaging times for each class and category.

Table 2-9. Proposed NOx and CO Emission Limits

Equipment Category		Emission Limits (ppmv)(1) NOx	Emission Limits (ppmv)(1) CO	Averaging Time (Rolling)(2)
Boilers	<20 MMBtu/hr	40/5(3)	400	24-hour
Boilers	≥20 – <40 MMBtu/hr	40/5(3)	400	24-hour
Boilers	≥40 – ≤110 MMBtu/hr	5	400	24-hour
Boilers	>110 MMBtu/hr	5	400	24-hour
Flares		20	400	2-hour
FCCU		2 5	500	365-day 7-day
Gas Turbines Fueled with Natural Gas		2	130	24-hour
Gas Turbines Fueled with Gaseous Fuel other than Natural Gas		3	130	24-hour
Petroleum Coke Calciners		5 10	2,000	365-day 7-day
Process Heaters	< 20 MMBtu/hr	40/9(4)	400	24-hour
Process Heaters	≥20 – <40 MMBtu/hr	40/9(4)	400	24-hour
Process Heaters	≥40 – ≤110 MMBtu/hr	5	400	24-hour
Process Heaters	>110 MMBtu/hr	5	400	24-hour
SRU/TG Incinerator		30	400	24-hour
SMR Heaters		5	400	24-hour
SMR Heaters with Gas Turbine		5	130	24-hour
Sulfuric Acid Furnaces		30	400	365-day
Vapor Incinerators		30	400	24-hour

(1) BARCT NOx limits for all equipment categories are specified at 3% oxygen correction, except for Gas Turbines and SMR Heaters with Gas Turbine which are specified at 15% oxygen correction.

(2) Averaging times apply to units operating a certified CEMS. Requirements, including averaging times, for units without CEMS are in the source test subdivision of the rule.

(3) The 40 ppmv limit is effective 6 months after rule adoption, the 5 ppmv limit is effective upon burner replacement.

(4) The 40 ppmv limit is effective 6 months after rule adoption, the 9 ppmv limit will be effective ten years after rule adoption burner replacement.

Boilers and Process Heaters Less than 40 MMBtu/hour

The BARCT assessment for boilers and process heaters less than 40 MMBtu/hour lists two NOx limits. As detailed in Appendix B, the technical assessments concluded 5 ppmv NOx is technically feasible based on burner technology for boilers less than 40 MMBtu/hour; however, the cost-effectiveness analysis concluded it was not cost-effective to require replacement of existing burners. The assessment of the existing units showed all boilers less than 40 MMBtu/hour are currently achieving less than 40 ppmv. PR 1109.1 requires boilers less than 40 MMBtu/hour to comply with the 5 ppmv limit when 50 percent or more of the burners are replaced or the replaced burners represent 50 percent or more of the heat input of the boiler.

Similarly, as detailed in Appendix B, the technical assessments concluded 9 ppmv NOx is technically feasible based on emerging burner technology for process heaters less than 40 MMBtu/hour; however, the cost-effectiveness analysis concluded it was not cost effective to require replacement of existing burners. The assessment of the existing units showed all but two process heaters less than 40 MMBtu/hour are currently achieving less than 40 ppmv. PR 1109.1 has a different timeframe for when a process heater must comply with the 9 ppmv limit because it is based on emerging technology. The 9 ppmv limit will not be required until ten years after rule adoption and only when 50 percent or more of the burners are replaced or the replaced burners represent 50 percent or more of the heat input of the process heaters.

Establishing Conditional NOx Limits

Once the NOx limits were established, staff evaluated the data to see if there are any cost outliers. Cost outliers tend to arise when units are used at low capacities, if the emission reductions are low, which typically occurs for units performing near the proposed BARCT NOx limits. Staff tries to provide relief for projects with very high costs that do not result in significant emission reductions. South Coast AQMD rules typically address these outliers by including low-use or low-emitting exemptions, or by allowing a higher conditional limit for units already achieving close to the proposed limit. Staff formerly referred to these as “near-limits” but will now refer to them as “conditional limits,” as conditional limits better describe these alternative emission limits as the rule will include conditions for when a unit can be subject to these limits.

Facilities cannot install a new NOx control technology and request the conditional limit for that unit. The intent of the conditional NOx limit is to recognize units with existing NOx control technology that are meeting the conditional limit at times, but possibly not continually, or can take action to lower the emissions to the conditional limit. For example, facilities may be able to reduce emissions on well-controlled units to below the conditional limits by performing maintenance, tuning the SCR, upgrading catalyst, or improving the ammonia injection grid. The conditional limit could address concerns with stranded assets for those facilities previously investing in expensive controls. The rule will require those units to have a conditional permit limit shortly after rule adoption. The short timeframe is because those units should already be achieving below, or close to, the proposed conditional limits with little to no modifications needed to meet conditional limits. Units performing below the NOx concentration limit in Table 1 of PR 1109.1 will not be eligible to use the conditional limit, regardless of whether the unit has a permit condition with a higher NOx limit. Conditional NOx and CO emission limits are listed for each class and category. PR 1109.1 includes separate provisions for units listed in Attachment D of PR 1109.1. These units are pre-qualified, and operators are not required to implement an early permit submittal, and the NOx level established for the unit may be higher than Table 2 NOx Conditional Limits. An operator that is making changes to their unit to meet a Table 1 or Table 2 NOx limit will need to be sure that all requirements are met, including requirements if Regulation XIII – New Source Review is triggered.

WSPA Comment on Conditional Limits

Staff has received a public comment requesting to clarify that the proposed conditional limits are in fact BARCT for the sources to which they apply. Staff agrees with this interpretation. In essence, the proposed conditional limits apply to specific categories of sources that meet the criteria of having both a high cost-effectiveness and minimal potential for emission reductions if they were held to the otherwise-applicable BARCT limit. In addition, these sources are expected to be able to meet the conditional limits without installing new control equipment. Finally, the sources subject to the conditional limits were selected so as to ensure that the sources remaining in the original class or category of sources analyzed for BARCT determination would have an overall cost-effectiveness not exceeding $50,000 per ton of NOx reduced. According to the California Supreme Court, the District's selection of a class or category of source for BARCT rules will not be disturbed unless it is "arbitrary, capricious, or irrational." *American Coatings Ass'n. v. South Coast Air Quality Management Dist.*, 54 Cal. 4th 446, 474 (2012). Review under the arbitrary and capricious standard is more deferential than the substantial evidence standard (*American Coatings*, 54 Cal. 4th 446, 475). There the court noted that the District carefully considered the comments of the affected industry and provided a reasoned explanation for its choices. Therefore, the court held "We will not disturb the District's judgment simply because there is evidence, even substantial evidence, supporting a different classification." (*American Coatings, supra,* 54 Cal. 4th 446, 475).

Establishing Interim NOx Limits

PR 1109.1 includes interim limits that will serve as a bridge after facilities transition out of RECLAIM before they are required to meet the proposed limits in PR 1109.1. U.S. EPA has commented that since facilities in RECLAIM are operating under an emissions cap, an enforceable mechanism, such as interim limits, are needed to ensure emissions from each source do not increase and adversely affect progress towards attainment and to ensure compliance with Section 110(l) of the federal Clean Air Act. Interim limits are set at levels to prevent backsliding, reflect current NOx emission levels, and are not intended to require the facilities to install additional emission controls. Staff evaluated existing NOx concentration levels that are currently being achieved based on existing permits, source tests, and CEMS data. Interim NOx and CO emission limits are listed in the individual sections for each class and category.

WSPA Interim Limit Comment

During the rulemaking process, the WSPA provided an alternative option to the interim limits. WSPA proposed facilities stay in the RECLAIM program until all units at the RECLAIM facilities meet the NOx emission limits in PR 1109.1. Due to the number and scope of emission control projects that will be required to comply with PR 1109.1, staff anticipates there could be some units that do not meet the PR 1109.1 NOx limits approximately until 2033. Under the WSPA proposal, facilities would remain in the RECLAIM program unit 2033 or beyond. Further, under this approach, facilities could use RTCs in lieu of installing emission control equipment until the last unit was required to meet the PR 1109.1 NOx emission limit. Staff consulted with the U.S. EPA and CARB, and both agencies agreed that use of RTCs cannot be used to meet BARCT limits established under Proposed Rule 1109.1 as this approach would be in direct conflict with the intent of AB 617. Staff had a detailed discussion of this approach in the July 2021 RECLAIM Working Group Meeting.

BARCT Compliance Timeline

Assembly Bill 617 requires BARCT implementation by December 31, 2023. By definition under the Health & Safety Section 40406, BARCT is an "emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source." As such, staff conducted an extensive BARCT analysis in accordance with the state law evaluating various emission control technologies and their emission reduction performance, as well as costs for each class and category of equipment. The lower the NOx concentration limit required during the operation of the refinery equipment; the more emission reductions are generated. Maximizing NOx emission reductions not only satisfies the goals of a BARCT assessment, but it is also critical in meeting the region's ambient air quality standards as NOx is a constituent of ozone pollution and precursor to PM. According to the 2016 AQMP, the region needs to reduce NOx emissions 45 percent by 2023 and 55 percent by 2031 in order to meet the 80 ppb and 75 ppb ozone standards, respectively. As noted earlier in this staff report, the 2016 AQMP directed the transition from RECLAIM into command-and-control approach, and in doing so, reduce NOx emissions by at least 5 tons per day. Not achieving these NOx emission reductions also puts the burden on other sources to reduce their emissions further to make up for what is not achieved by this rule.

In conducting the BARCT NOx limit, the analysis focused on technologies that can achieve the maximum degree of reduction. For most equipment categories such as large boilers and heaters greater than or equal to 40 MMBtu/hour, this technology is Selective Catalytic Reduction or "SCR." Large boilers and heaters are the largest emissions category under PR 1109.1, representing approximately 60 percent of the NOx emissions. Low NOx burners are another control technology that could more easily be replaced in existing units at a lower cost than SCR, but the emission reductions are also lower potentially achieving 40-50 ppm. On the contrary, more effective NOx controls, such as ultra-low NOx burners (ULNB) can reduce NOx to 25-30 ppm, and if installed in combination with a Selective Catalytic Reduction (SCR), which reduces NOx 90-95%, can achieve less than 2 ppm. Thus, in satisfying the BARCT goal of "maximum degree of reduction achievable," staff initially proposed a 2 ppm NOx limit for large heaters and boilers to maximize emission reductions but due to safety concerns with installing ULNB in older units and the high costs of control technology to achieve 2 ppm, such as multiple ammonia injection grids, it is determined to not be cost effective for large heaters and boilers to meet 2 ppm. However, it is cost effective to achieve 5 ppm with less costly and technically feasible control technology such as a single stage SCR.

The affected refineries were built 50 to over 100 years ago and while equipment has changed over the years, most of the equipment affected by the rule is old and the spacing configuration of the sites are dense. Thus, to install pollution control requires creative engineering and design to accommodate the space necessary and perform properly. Some projects currently taking place involve building vertically requiring deep earth pylons to support the structure housing the control technology or constructing complex ducting to house the SCR catalyst beds that stretch long distances horizontally away from the basic equipment. So, while technically these projects could feasibly be constructed, the costs are in the millions of dollars which have been provided by the refineries and used in the BARCT analysis. Needless to say, time will be needed to design and complete these complex engineering projects necessary to install the controls that will achieve the maximum emission reductions from a 5 ppm NOx limit for large heaters and boilers as opposed to more simple projects, such as low-NOx burners, that would take less time but result in much less emission reductions from a higher 40-50 ppm NOx limit.

The proposed rule provides various options, under the I-Plan, by which an affected facility is required to meet emission reduction targets by certain deadlines crafted to ensure implementation of BARCT including the necessary steps for a successful project. Such necessary steps include design and engineering, permit application submittal, permit evaluation and issuance, budgeting, logistics, purchasing equipment, installation, and testing. Again, the affected facilities are decades old so over time space to install new control equipment has become very limited. The staggered structure of the deadlines in the options reduce demand for certain resources since the refineries will be competing for same pool of skilled labor, equipment manufacturers, source testing companies, etc. In addition, integrating projects into the scheduled turnarounds at the refineries assist in minimizing downtime and fuel supply disruptions. Refineries turnarounds are typically every three to five years, but certain complex equipment, such as the FCCU and crude unit, could have longer turnaround times of eight to ten years. In those cases, if the project turnaround is scheduled before the first phase, then those projects will likely be slated for their next turnaround time in eight to ten years. The I-Plan options are designed for early and high emission reductions that allow for longer implementation time for the units that have longer implementation schedules.

Other implementation considerations include the number of highly complex projects that will result from the proposed rule. Staff estimates approximately 75 SCR projects and approximately ~~25~~15 SCR upgrades needed to meet the stringent NOx limits, which need time to be implemented, especially as noted earlier there are competitive demands for resources. SCR projects tend to be customized to the site and location and require complex engineering due to the challenges in integrating equipment within the existing facility structure. These projects are costly ranging from $10 million to $70 million to complete, with total facility cost ranging from $179 million to one billion dollars.

While AB617 requires implementing BARCT by December 31, 2023, it would be unreasonable and unfeasible to *fully* implement, such as achieving BARCT limits, for all BARCT projects subject to PR1109.1. However, it should be noted, some BARCT projects will be fully implemented, and emission reductions will be achieved before December 31, 2023. In addition, with a deadline of January 1, 2024 to demonstrate compliance with 50% emission reductions from the largest refinery in the region, Option 4 alone will achieve over one ton per day of NOx emission reductions or 16 percent of the total project emission reductions. If time is not provided for the implementation of the other projects, the proposed rule risks not achieving over six tons per day of emission reductions since it is just not feasible to implement these complex emission reduction projects in such a short period of time given all the elements in the process as discussed earlier. Again, due to the high number of affected units requiring control device installations, potentially limited trained labor pool, competition for equipment and material, high cost of the projects, compliance with permitting and CEQA, not all projects can feasibly be completed to meet the stringent NOx limits in the rule. Feasibility is a parameter in determining BARCT so if the implementation to install SCR to achieve the stringent limit of 5 ppm is not feasible, then the BARCT analysis would need to be modified to focus on low NOx burners and the NOx BARCT limit would be increased t to meet the December 31, 2023 deadline so likely fewer emission reductions would be obtained. This would affect the overall emission reduction benefit potential of the rule by not requiring the most stringent limit.

Finally, because technology evolves and improves over time, periodic checks as to what is current BARCT, an evaluation of any new pollution control technologies that are commercially available and cost-effective. If a shorter implementation schedule is a limiting factor in imposing stringent NOx limits, then higher NOx limits would be deemed BARCT for PR1109.1 resulting in less emission reductions, In addition, it is highly unlikely a revised BARCT analysis to lower, for example, a 40 ppm limit to 5 ppm in a future rulemaking would be cost effective as the incremental emission reductions would be smaller. Thus, foregone emission reduction potential as a result of not allowing longer feasible implementation time would have a permanent impact. PR 1109.1 is designed to achieve the greatest NOx emission reductions, with a strong emphasis on earlier reductions.

Clean Air Act Section 110(l) and Subdivision (o) Exemptions
State Implementation Plans (SIPs) are developed under Section 110 of the Federal Clean Air Act (CAA) for the purpose of protecting the National Ambient Air Quality Standards (NAAQS), which are health-based standards related to the six criteria pollutants: particulate matter (both $PM_{2.5}$ and PM_{10}), nitrogen dioxide, carbon monoxide, lead, sulfur dioxide, and ozone. Section 110(l) of the CAA prohibits the Environmental Protection Agency (EPA) from approving a revision to a SIP if the revision would interfere with any applicable requirement concerning attainment of the NAAQS or reasonable further progress toward attaining the NAAQS. Exemptions in subdivision (o) of Rule 1109.1 will comply with CAA Section 110(l) as the NOx emission limit requirements will not result in an emission increase that would interfere with the South Coast's ability to attain or maintain compliance with the NAAQS.

The exemptions provided in subdivision (o) are consistent with current operation and historical emissions data for the units. In addition, each unit must maintain or submit a complete permit application on or before July 1, 2022, pursuant to paragraph (f)(5) for an enforceable permit condition that will limit the usage. The following exemptions are provided in subdivision (o) of the rule:

Table 2-10. Exemptions and CAA Section 110(l)

Units	Rule Exemption	Requirement	Section 110(l) Demonstration
Process heaters and boilers less than 2 MMBtu/hour	Paragraph (o)(1)	Units used exclusively for space heating are exempt from Rule 1109.1	Units are subject to Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters
Low-use boilers less than 40 MMBtu/hour	Paragraph (o)(2)	Operated 200 hours or less per year and enforceable permit condition of 200 hours. Unit must also not be included in approved B-Plan or B-Cap	Impacts one boiler equipped with LNB and a permit limit of 9 ppm. Boiler is operated infrequently and only operated as a back-up when primary boiler is down for state inspections. No emissions increase or change in operation.
Low-use process heater rated greater than or equal to 40 MMBtu/hour	Paragraph (o)(3)	Units fired less than 15 percent of rated heat input capacity per calendar year and must have a permit condition that limits the firing rate.	Addresses limited number of process heaters that are infrequently used. Majority of all process heaters are utilized at 50 percent capacity or greater. No changes in operation or emissions increase.
FCCU bypassing post combustion control to conduct CO boiler inspection	Paragraph (o)(4)	Boiler inspections required under California Code of Regulations, Title 8, section 770(b)	CO boiler located downstream of FCC regenerator are subject to internal and external inspection pursuant to California Code of Regulations which require bypassing the CO boiler to conduct inspection
FCCU Startup Boilers and Process Heaters	Paragraph (o)(5)	Unit is operated 250 hours or less per calendar year and must have a permit condition that limits the operating hours to less than 250 hours per calendar year. Exempt	Heaters are only operated during FCC start-up which occurs once every several years. When operated, emissions are less than 0.002 tons

Units	Rule Exemption	Requirement	Section 110(l) Demonstration
		from subdivision (k), (l), (m) if unit is not included in approved B-Plan or B-Cap.	per day. No change from current operation or emissions increase.
Start-up and shutdown boilers and process heaters at sulfuric acid plants	Paragraph (o)(6)	Unit must have permit condition that limits the heat input to 90,000 MMBtu or lower per calendar year. Exempt from subdivision (k), (l), (m) if unit is not included in approved B-Plan or B-Cap.	Process heaters are only used to preheat the converter during startup of the processing unit and typically operated less than 10% of the annual limit specified in permit limit, based on annual fuel usage. Boiler located only at one facility and not operated when processing unit is operating. Only operated as much as needed. No change in current operation or emissions increase.
Boiler or process heater operating the pilot prior to start-up or shutdown	Paragraph (o)(7)	Startup/shutdown condition emissions not included in rolling average compliance demonstration	Applicable during startup /shutdown periods only. Startup duration limited pursuant to PR 429.1. Fuel usage is minimal when maintaining pilots, thus no emissions increase.
Flares (Ground)	Paragraph (o)(8)	Flare that emits less than or equal to 550 pounds of NOx per calendar year and must have an enforceable permit condition that limits emissions not to exceed 550 pounds per year	550-pound permit limit requirement is based on historical emissions data. No change in current operation or emissions increase.
Vapor Incinerators less than 2 MMBtu/hr per calendar year	Paragraph (o)(9)	Units emitting less than 100 pounds per calendar year and must have an enforceable permit condition Units emitting greater than 100 but less than 1,000 pounds per calendar year shall be exempt until unit replacement or ten years after rule adoption, whichever is sooner; must have enforceable permit condition that limits emissions to less than 1,000 pounds per calendar year	*No technical, feasible retrofit control option; Unit replacement only feasible option* Units emitting 100 pound or less per calendar year are infrequently used and only when needed. Permit limit based on historical emissions data, thus no emissions increase. Units emitting greater than 100 but less than 1,000 pounds per year permit limit is based on historical emissions data and will be required to replace with newer unit within 10 years. No change in operation or emissions increase from category.

To further ensure that the provided exemptions do not interfere with South Coast's ability to maintain or meet NAAQS, paragraph (f)(6) of the rule requires that any exemption exceedances pursuant to paragraphs (o)(2), (o)(3), (o)(5), (o)(6), (o)(7), (o)(8), and (o)(9) will require the owner or operator to submit a permit application for a permit condition based on Table 1 NOx Concentration Limit and corresponding CO concentration within six months of exceedance. Furthermore, subparagraph (f)(7)(B) addresses when an owner or operator fails to submit a permit application for an exempt unit and will be required to meet the applicable NOx and CO concentration limits in Table 1, 24 months after July 1, 2022. In addition, PR 1109.1 includes recordkeeping requirements for all units and includes provision to ensure applicable exemptions are being enforced such as meters to ensure that unit is below the applicable exemption. An owner or operator of a Facility shall maintain the following daily records for each Unit, in a manner approved by the Executive Officer:

(A) Time and duration of startup and shutdown events;
(B) Total hours of operation;
(C) Quantity of fuel; and
(D) Cumulative hours of operation for the calendar year.

Staff believes that with the provision set forth in the rule, it has addressed the requirements of CAA Section 110(l) and is consistent with EPA requirements for adopting new rules into the SIP.

SUMMARY OF THE BOILER AND HEATER BARCT ASSESSMENT

Background

The largest equipment category under PR 1109.1 is the boilers and process heaters category, those units represent over 60 percent of the NOx emission sources at refineries and related industries. Process heaters are indirect-fired heaters designed to supply the heat necessary to raise the temperature of feedstock to the distillation or reaction levels. Process heaters are used extensively in various processing units throughout the refining industry with some having specialized applications, design arrangements, capacities, and combustion fuel sources. Staff evaluated several types of heaters as separate categories due to design differences. Specialized heaters are used for different purposes and may combust different fuel types, such as refinery gas, natural gas, pressure swing adsorption (PSA) off gas, sulfur, and hydrogen sulfide. Examples of specialized heaters include SMR heaters located in hydrogen plants which can have over 350 small burners and sulfuric acid furnaces which only have two large burners. Each burner type will have different design requirements for the intended application and have different associated costs.

Boilers are combustion sources used to generate the steam necessary for plant operations. Steam is primarily used for heating, separating hydrocarbon streams, hydrogen production, as a stripping medium, and to produce electricity by expansion through a turbine. There are also two specialized boiler applications that were considered separately: CO boilers and heat recovery boilers. The specialized boilers are typically associated with other units at the refinery. Although the term "boiler" typically describes a heater that generates steam, CO boilers in PR 1109.1 are heaters that process waste gas from the FCCU with an integral waste heat recovery system used to produce steam. There is one CO boiler that will be subject to PR 1109.1 and that unit will be subject to the NOx limits of the corresponding FCCU since the flue gases exit through a common stack. Similarly, a heat recovery boiler's main function is to recover excess waste heat to generate steam. However, unlike the CO boiler, heat recovery boilers are unfired units and are not a source of NOx; therefore, heat recovery boilers are not subject to PR 1109.1. An example of a heat recovery boiler is a boiler unit located downstream of a gas turbine referred to as a Heat Recovery Steam Generator (HRSG). Further discussion regarding the CO boiler can be found in Appendix B.

Due to the variety of boilers and process heaters that will be subject to PR 1109.1, staff segregated them into six major subcategories prior to conducting the BARCT assessment. Figure 2-3 shows the six subcategories.

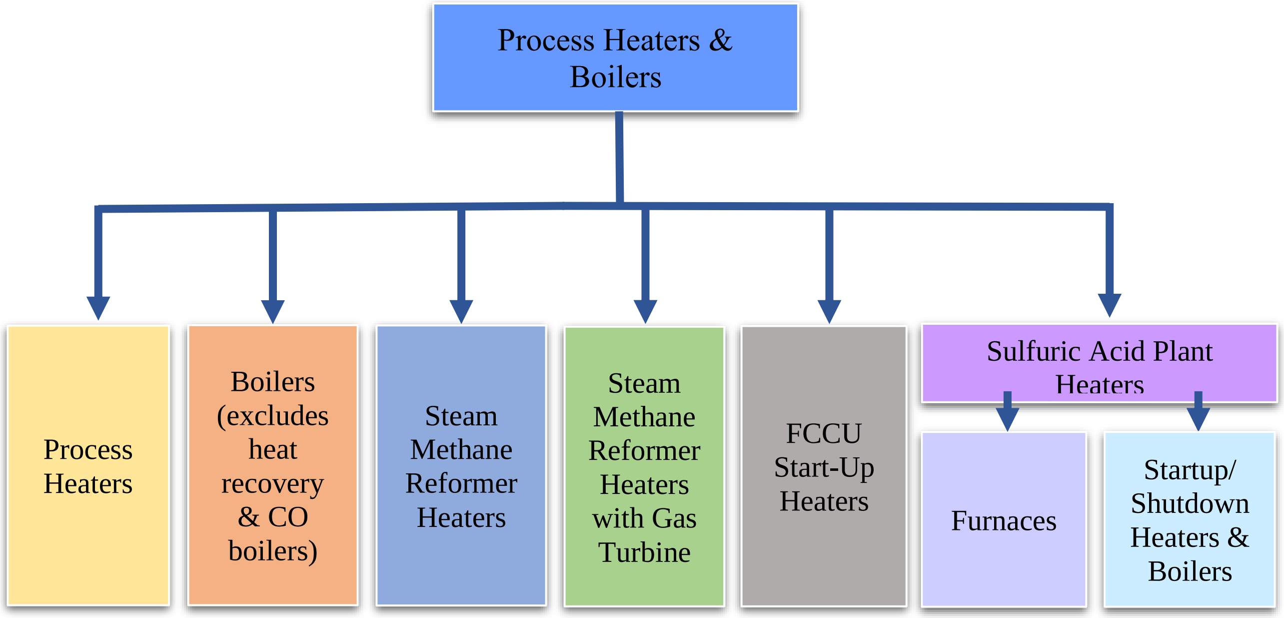


Figure 9. Six Major Sub-Categories of Boilers & Process Heaters Category

Each of the large boiler and process heater subcategories were divided into smaller categories based on size or maximum rated heat input in order to conduct a more granular BARCT assessment. Equipment was also grouped into subcategories to reflect the applicable technology control options. Staff divided the boilers and heaters into the four category sizes as described in the table below for the purpose of BARCT assessment.

Table 2-11. Boiler and Process Heater Size Categories

Heaters and Boilers Size Categories
<20 MMBtu/hr
≥20 to <40 MMBtu/hr
≥40 to ≤110 MMBtu/hr
>110 MMBtu/hr

The size categories were established based on the initial cost-effectiveness calculation that demonstrated it would not be cost effective to install SCRs on units less than 40 MMBtu/hour. Staff went one step further to separate categories into four size sub-categories to ensure the larger units with more emission reduction potential were not driving down the average cost-effectiveness of the class and category.

NOx Limits that Represent BARCT

The initial BARCT Assessment was presented in Working Group Meeting #9 on December 12, 2019 and updated in the following Working Group Meetings: #10 on February 18, 2020, #13 on August 12, 2020, #15 on November 4, 2020, #17 on February 4, 2021, #18 on February 11, 2021, and #19 on March 4, 2021. The large boiler and heater categories were reassessed using revised cost data to determine conditional limits at Working Group Meeting #22 on June 30, 2021. The table below summarizes the BARCT assessment for boilers and process heaters that were demonstrated to be technically feasible and cost-effective (see Appendix B for the detailed analysis).

Table 2-12. Summary of BARCT NOx Assessment for Boilers and Heaters

Equipment Category[1]	Assess South Coast AQMD Regulatory Requirements	Assess Emission Limits of Existing Units	Assess Other Regulatory Requirements	Assess Pollution Control Technologies	Initial BARCT Emission Limit
Boiler (size MMBtu/hr)					
<20	12 ppmv	3 - 58 ppmv	9 - 30 ppmv	2 ppmv	40/5[3] ppmv
≥20 - <40	9 ppmv	3 - 81 ppmv	9 - 30 ppmv	2 ppmv	40/5[3] ppmv
≥40 - ≤110	25/2 ppmv	68 - 80 ppmv	5 - 9 ppmv	2 ppmv	5 ppmv
>110	5/2 ppmv	4.2 - 117 ppmv	5 - 9 ppmv	2 ppmv	5 ppmv
Process Heater (size MMBtu/hr)					
<20	12 ppmv	3 - 58 ppmv	9 - 30 ppmv	2 ppmv	40/9[4] ppmv
≥20 - <40	9 ppmv	3 - 81 ppmv	9 - 30 ppmv	2 ppmv	40/9[4] ppmv
≥40 - ≤110	25/2 ppmv	1.4 - 134 ppmv	9 - 30 ppmv	2 ppmv	5 ppmv
>110	5/2ppmv	1.5 - 70 ppmv	9 - 30 ppmv	2 ppmv	5 ppmv
SMR Heater					
All	2 ppmv	3.6 - 7.2 ppmv	5 ppmv	2 - 5 ppmv	5 ppmv
SMR Heater with Gas Turbine					
All	N/A	4.4 ppmv	N/A	3 - 5 ppmv	5 ppmv
Sulfuric Acid Furnace					
All	N/A	23 - 60 ppmv	N/A	2 and 20 ppmv	30 ppmv

(1) BARCT NOx limits for all equipment categories are corrected to 3% oxygen, except for SMR Heaters with Gas Turbine which are corrected to 15% oxygen.

(2) Concentration limits based on technology assessment represent the maximum NOx emission reductions for optimal installation without consideration for cost.

(3) The 40 ppmv limit is effective on January 1, 2023, the 5 ppmv limit is effective upon burner replacement.

(4) The 40 ppmv limit is effective on January 1, 2023, the 9 ppmv limit is effective 10 years after rule adoption upon burner replacement.

The BARCT assessment was conducted for each class and category listed in the table above. After conducting the BARCT assessment, some equipment size categories were combined for the same equipment type where the proposed NOx limit was the same. For example, where the BARCT assessment of related classes or categories of equipment concluded the same NOx limits were technically feasible and cost-effective, those categories were combined to streamline the rule requirements. For example, the boilers and process heater BARCT assessment evaluated four size categories (<20 MMBtu/hour, 20 to <40 MMBtu/hour, 40 to 110 MMBtu/hour, and >110 MMBtu/hour) but the PR 1109.1 Table 1 NOx limits are based on two size categories (<40 MMBtu/hour and ≥40 MMBtu/hour).

Conditional Emission Limits

Boilers and Process Heaters

Staff established conditional emission limits for boilers greater than 110 MMBtu/hour, process heaters between 40 to 110 MMBtu/hour, process heaters greater than 110 MMBtu/hour, and SMR heaters due to high cost-effectiveness for the class and category or high cost-effectiveness of some units.

For boilers greater than 110 MMBtu/hour, the class and category are cost effective for all units to meet the 5 ppmv NOx limit; however, there were a couple of units operating near the 5 ppmv limit with very high cost-effectiveness (more than $200,000 per ton reduced) that the rule will address. Staff identified five units operating at less than 7.5 ppmv as cost outliers and will include a conditional limit of 7.5 ppmv for boilers >110 MMBtu/hour. The potential emission reductions if those units were required to meet 5 ppmv is 0.02 tons per day with a cost of almost $20 million dollars.

Rule 1109.1 also establishes a second criteria that boilers greater than 110 MMBtu/hour with the potential emission reduction of more than 20 tons per year NOx emissions. The potential emission reductions are based on the difference of the baseline emissions and the PR 1109.1 Table 1 concentration limit, scaled to the baseline emissions. This second condition is to ensure those units with high emission potential will not be allowed to hold higher NOx limits. The conditional limits are intended for units that are already well controlled, including SCR controls.

For process heaters greater than or equal to 40 MMBtu/hour, the revised cost estimates that were provided by refineries to staff in March 2021 resulted in a cost-effectiveness greater than $50,000 per ton of NOx reduced. Staff used all of the revised refinery costs even though the facilities provided few details on the scope of the projects or justification for the significant cost increases received from some facilities. To reduce the average cost-effectiveness, staff identified units with high-cost effectiveness operating near the 5 ppmv limit in order to reduce the overall cost of the rule. An iterative process, summarized in the figure below, was used to identify the conditional NOx concentration level where the cost-effectiveness for units above the conditional emission limit would be less than $50,000 per ton of NOx reduced. The NOx reduction projects for units already achieving lower NOx emission typically represent cost outliers. Table below shows the Boilers and Heaters performing under conditional limits.

Table 2-13. Boilers and Heaters Performing under Conditional Limits

Facility ID	Category	Device ID	Size (MMBtu/hr)	Proposed BARCT limit (ppmv)
800436	Boiler	D1122	140	7.5
800026	Boiler	D1550	245	7.5
181667	Boiler	D1236	340	7.5
181667	Boiler	D1239	340	7.5
171109	Boiler	D429	352	7.5
800436	Heater	D384	48	18
800436	Heater	D385	24	18
174655	Heater	D419	52	18
181667	Heater	D231	60	18
181667	Heater	D232	60	18
181667	Heater	D234	60	18
181667	Heater	D235	60	18
800436	Heater	D770	63	18
181667	Heater	D950	64	18
800026	Heater	D768	110	18
800026	Heater	D6	136	22
800436	Heater	D388	147	22
171109	Heater	D78	154	22
800030	Heater	D643	220	22
174655	Heater	D532	255	22
174655	Heater	D63	300	22
800030	Heater	D82	315	22
800030	Heater	D83	315	22
800030	Heater	D84	219	22
<u>800030</u>	<u>Heater</u>	<u>D466</u>	<u>62</u>	<u>18</u>
<u>800030</u>	<u>Heater</u>	<u>D467</u>	<u>62</u>	<u>18</u>
800436	Heater	D388	147	22
~~800436~~	~~SMR Heater~~	~~D777~~	~~146~~	~~7.5~~
~~174655~~	~~SMR Heater~~	~~D1465~~	~~427~~	~~7.5~~

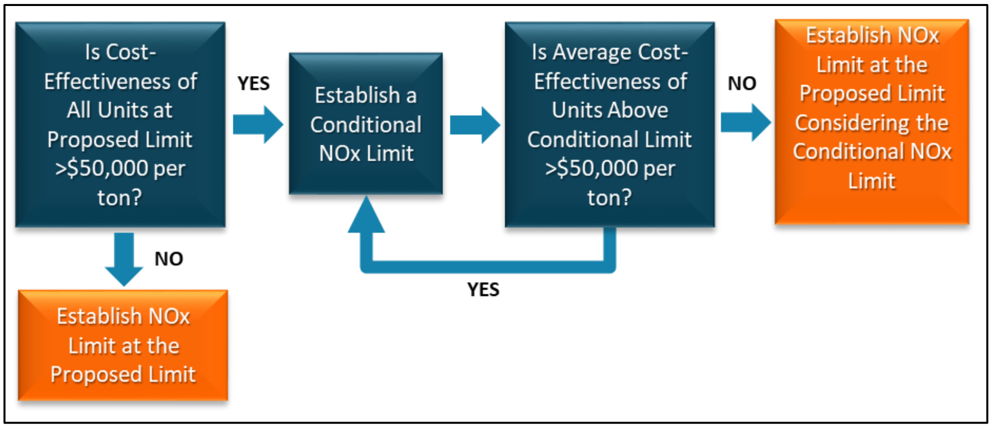
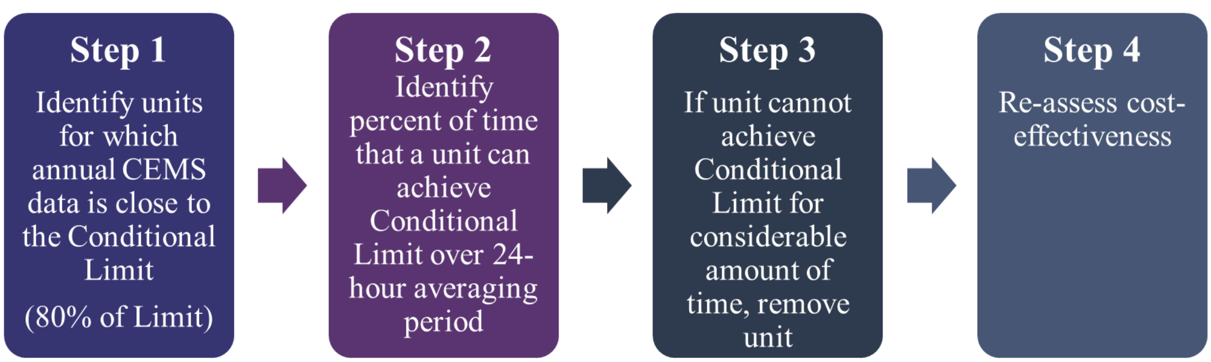


Figure 10. Process to Establish Conditional NOx Limits For Large Process Heaters

When staff presented the conditional NOx limit assessment, WSPA disagreed with the approach to remove cost outliers and commented that the process used to identify units that could potentially meet the conditional limits for boilers and process heaters greater than or equal to 40 MMBtu/hour was flawed. Staff relied on annual NOx CEMS data to identify the NOx levels that units could achieve. WSPA disagreed with this assessment as the units will be required to meet the Rule 1109.1 limits based on a 24-hour average. Staff presented the iterative process used for establishing the conditional limits, as shown in the above figure, by evaluating the overall cost effectiveness of the class and category and removing units from the average, starting with units performing near the proposed BARCT limit. The iterative process was repeated until the class and category cost effectiveness were less than $50,000 per ton of NOx reduced and the conditional limits was established based on that process. In addition, based on the WSPA comment on the averaging time used in the assessment, staff reviewed the CEMS data for the units performing near the established conditional limits to ensure the units could meet the conditional limits based on the proposed averaging time in the rule. While the RECLAIM program is based on annual compliance, command-and-control rules, such as PR 1109.1, require compliance to be demonstrated based on shorter averaging periods. Staff re-evaluated the CEMS data for the units performing below the conditional limits based on a 24-hour average to ensure those units met the conditional emission limit over a considerable amount of time (e.g., 80 percent). Refer to the appendices for more discussion and detailed analysis of conditional emission limit for each of the equipment classes.



In evaluating the process heaters between 40 and 110 MMBtu/hour and heaters greater than110 MMBtu/hour, several units with different sizes were identified with combined stacks. For the conditional limit assessment, staff considered units to fall into the larger category if even one of the combined units was less than110 MMBtu/hour.

Table 2-14. Applicable NOx Limit for Units with Combined Stacks

Unit Sizes for Combined Stacks			Unit Size for Determining NOx Limit Based
<40 MMBtu/hr	≥40 to ≤110 MMBtu/hr	> 110 MMBtu/hr	
Yes	Yes	No	≥40 to ≤110 MMBtu/hr
Yes	No	Yes	> 110 MMBtu/hr
Yes	Yes	Yes	> 110 MMBtu/hr
No	Yes	Yes	> 110 MMBtu/hr

For process heaters between 40 and 110MMBtu/hour, staff determined a conditional emission limit of 18 ppmv would reduce the cost-effectiveness to less than $50,000 per ton of NOx reduced. Rule 1109.1 also establishes a second criteria that facilities cannot apply for the conditional limit for process heaters between 40 and 110MMBtu/hour if the potential emission reduction project is more than 10 tons per year in NOx emissions. The potential emission reductions are based on the difference of the baseline emissions and the PR 1109.1 Table 1 concentration limit, scaled to the baseline emissions. This second condition is to ensure those units with high emission potential will not be allowed the higher NOx limits. The conditional limits are intended for units that are already well controlled, including SCR controls.

For process heaters greater than 110 MMBtu/hour, staff determined a conditional emission limit of 22 ppmv would reduce the cost-effectiveness to less than $50,000 with a second criteria for projects that had the potential to reduce emissions more than 20 tons per year; those projects have an average cost-effectiveness of $44,000 per ton of NOx reduced and represent 1.6 tons per day of NOx emission reductions from this class. Rule 1109.1 also establishes a second criteria that process heaters >110 that have a potential emission reduction of 20 tons per day of NOx are not eligible for the conditional 22 ppmv limit. The potential emission reductions are based on the difference of the baseline emissions and the PR 1109.1 Table 1 concentration limit, scaled to the baseline emissions. The specific units staff identified as meeting the conditional limits are listed in Appendix B.

SMR Heaters

For SMR heaters, three units were identified achieving greater than the proposed 5 ppmv BARCT NOx limit that had very high cost-effectiveness. The entire class and category is cost-effective, but these three units are cost outliers with an estimated Present Worth Value for SCR upgrade to meet 5 ppmv up to $10,000,000 with potential NOx emission reductions of 0.015 tons per day. For this category, the rule will include a conditional NOx limit of 7.5 ppmv. A more detailed discussion and analysis can be found in Appendix B.

Interim Limits

Boilers and Process Heaters

Staff established interim NOx and CO emission limits based on the current emission levels or existing permit limits for boilers and process heaters. The interim limit for boilers and process heaters less than 40 MMBtu/hour will be 40 ppmv as most units already have permit limits at 40 ppmv. However, there are two heaters in the less than 40 MMBtu/hour category that are currently performing above 40 ppmv – NOx concentrations are 58 and 96 ppmv. To address these two heaters, staff has included an interim limit of 60 ppmv for heaters with a rated heat input <6 MMBtu/hour and for any unit in the category that is operating an approved CEMS, will be able to incorporate the heater in a compliance plan which will be subjected to facility-wide interim emission rate of 0.03 lb/MMBtu for the process heater category. For the larger units, the NOx concentrations range from less than 2 ppmv to over 130 ppmv and most units do not have permit limits. Staff considered setting a high concentration limit that would accommodate all units, but if the interim limit was set too high, operators with controlled units with SCRs could stop running them as efficiently, which would result in backsliding. For boilers and process heaters greater than or equal to 40 MMBtu/hour, the rule will have a limit consistent with the original Rule 1109, which is a facility-wide boiler and heater limit of 0.03 pounds per MMBtu based on the maximum firing rate of the units. The averaging time will diverge from the Rule 1109 15-minute average and instead be consistent with the current annual regulatory construct of RECLAIM. All interim limits will allow a 365-day rolling average as the interim limits are intended to prevent backsliding and not place further regulatory requirements on the facilities. Most interim limits will apply until a unit is required to meet another PR 1109.1 emission limit; however, since the 0.03 pounds per MMBtu limit is based on all boilers and process heaters, that limit will apply until all the boilers and process heaters greater than or equal to 40 MMBtu/hour at that facility are required to meet another PR 1109.1 emission limit. This does not add an additional burden to the facility as the emission level of pound per MMBtu will decrease as controls are installed. Instead, this requirement it is to prevent the facility-wide level to increase as low-emitting units are removed from that total.

~~The rule also includes a third option of the I-Plan compliance schedule that allows a lower emission reduction target during the initial phase available only for those facilities with lower emissions from large boilers and process heaters either because they already implemented a considerable number of NOx control projects, or the facility has newer, lower-emitting units. Facilities that elect to comply with the third option under I-Plan compliance schedule will have to meet an interim limit of 0.02 pounds per MMBtu based on the maximum firing rate of the units. Staff anticipates two facilities (Chevron and Valero Refinery) are currently eligible for this compliance schedule option.~~

Facilities that elect to comply with a B-Cap will be held to an annual mass cap. Those facilities will be held to a mass cap based on the 2017 emissions<u>. If the facility exits RECLAIM prior to the implementation of Phase 1 of an I-Plan, the facility emissions will be capped at the 2017 emissions, but if they exit after the implementation of one of the Phases in the I-Plan, the cap will be based on the emission reduction target for the applicable Phase</u>.

SMR Heaters

The interim limit for SMR heaters will be set based on current emission levels. The emissions for SMR heaters vary considerably depending on if there are SCRs installed so there will be two interim limits: 20 ppmv for units with existing SCRs and 60 ppmv for units without existing SCRs.

Averaging Times

For the units greater than or equal to 40 MMBtu/hour, staff initially proposed an eight-hour averaging time. Staff's third-party consultant Norton Engineering stressed the need for the longer averaging times to meet the low NOx levels being proposed. Due to the complexity and variability of the fuel composition in refinery fuel gas at facilities subject to PR 1109.1, Norton Engineering recommended a 24-hour averaging time to allow the facilities the time to achieve the proposed low-NOx levels. Demonstrating compliance of the concentration limit averaged over a period of time can be done when the emissions data is continuously monitored and collected. Units such as boilers and process heaters less than 40 MMBtu/hr that do not have CEMS will be dependent on periodic source tests to demonstrate compliance. Data collected during that source test will be based on approved source test protocols and are typically shorter periods of time such as 15-min or 2-hour averaging.

Carbon Monoxide Limits
PR 1109.1 establishes a 400 ppmv CO limit for boilers and process heaters, except for the SMR heater with a gas turbine where the CO limit is 130 ppmv, since these unit achieve lower CO levels. Any units with lower CO limits in existing permits will have to maintain the permitted limits.

Startup and Shutdown Boilers and Process Heaters
There are seven startup process heaters and one startup boiler that will be subject to PR 1109.1. Five of the heaters are used only during FCCU startup which can be once every 5 years. Two heaters and a boiler are used for sulfuric acid production units and are also used during unit startup. Based on the BARCT assessment, it is not cost-effective to retrofit these units due to the low emissions. FCCU startup heaters annual emissions are 0.002 tons per day, sulfuric acid start-up heaters are 0.00008 tons per day, and sulfuric acid start-up boiler is 0.0003 tons per day. These units will fall under a low-emissions exemption but will have to meet the applicable rule limits based on their size if the use exceeds the exemption threshold. The FCCU startup heaters will have a low-use exemption of 250 hours.

Emission Limit Summary
The table below summarizes the emission limits in PR 1109.1 for boilers and heaters. All averaging times in the tables below apply to units operating a certified CEMS. Units not required to operate CEMS will be required to demonstrate compliance based on a source test performed over no longer than 2 hours.

Table 2-15. PR 1109.1 Emission Limits for Boilers and Process Heaters

BOILERS			
Rated Heat Input Capacity (MMBtu/hour)	NOx (ppmv)	CO (ppmv)	Rolling Averaging Time[1]
	3% O_2 Correction		
<40	40/5[2]	400	24-hour
≥40	5	400	24-hour
PROCESS HEATERS			
Rated Heat Input Capacity (MMBtu/hour)	NOx (ppmv)	CO (ppmv)	Rolling Averaging Time[1]
	3% O_2 Correction		
<40	40/9[3]	400	24-hour
≥40	5	400	24-hour
STEAM METHANE REFORMER HEATERS			
Equipment Category	NOx (ppmv)	CO (ppmv)	Rolling Averaging Time[1]
	3% O_2 Correction		
SMR Heater	5	400	24-hour
STEAM METHANE REFORMER HEATERS WITH GAS TURBINE			
Equipment Category	NOx (ppmv)	CO (ppmv)	Rolling Averaging Time[1]
	15% O_2 Correction		
SMR Heater with Gas Turbine	5	130	24-hour
SULFURIC ACID FURNACES			
	NOx (ppmv)	CO (ppmv)	Rolling Averaging Time[1]
	3% O_2 Correction		
Furnace	30	400	365-day

(1) Averaging times apply to units operating a certified CEMS, units not required to operate CEMS will be required to demonstrate compliance based on a source test performed no longer than 2 hours.

(2) The 40 ppmv limit is effective on January 1, 2023, the 5 ppmv limit is effective upon burner replacement.

(3) The 40 ppmv limit is effective 6 on January 1, 2023, the 9 ppmv limit is effective 10 years after rule adoption upon burner replacement.

Table 2-16. Conditional NOx Emission Limits for Boilers and Process Heaters

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers >110 MMBtu/hour	7.5	400	3	24-hour
Process Heaters ≥40 – ≤110 MMBtu/hr	18	400	3	24-hour
Process Heaters >110 MMBtu/hr	22	400	3	24-hour
SMR Heaters	7.5	400	3	24-hour

(1) Averaging times apply to units operating a certified CEMS, units not required to operate CEMS will be required to demonstrate compliance based on a source test performed no longer than 2 hours.

Table 2-17. Interim NOx Emission Limits for Boilers and Process Heaters

Unit	NOx	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time(1)
Boilers and Process Heaters <40 MMBtu/hour	40 ppmv	400	3	365-day
Boilers and Process Heaters ≥40 MMBtu/hour	Pursuant to paragraphs (f)(2) (*see following Table*)	400	3	365-day
SMR Heaters	20 ppmv[2]	400	3	365-day
	60 ppmv[3]			365-day
SMR Heaters with Gas Turbine	5 ppmv	130	15	365-day

(1) Averaging times apply to units operating a certified CEMS, units not required to operate CEMS will be required to demonstrate compliance based on a source test performed no longer than 2 hours.
(2) SMR Heaters with post-combustion air pollution control equipment installed before date of rule adoption.
(3) SMR Heaters without post-combustion air pollution control equipment installed before date of rule adoption.

Table 2-18. Interim NOx Emission Limits for Boilers and Process Heaters ≥40 MMBtu/hour

Units	An Owner or Operator that Elects to Comply with an Approved:	Facility NOx Emission Rate (pounds/million Btu)	Rolling Averaging Time
Boiler and Process Heaters ≥40 MMBtu/hour	B-Plan or B-Cap using I-Plan Option 3	0.02	365-day
	B-Plan	0.03	365-day

Facilities that elect to comply with a B-Cap will be held to an annual mass cap. Those facilities will be held to a mass cap based on the 2017 emissions.

SUMMARY OF PETROLEUM COKE CALCINER BARCT ASSESSMENT

Background

The Marathon (Tesoro Refinery) petroleum coke calciner is the only equipment of its kind in the South Coast Air District and is operating under the NOx RECLAIM program. Based on the 2018 NOx survey questionnaire, this petroleum coke calciner has two connected combustion devices, a rotary kiln and pyroscrubber, that share a common stack equipped with a single CEMS. There are no existing NOx controls, but the equipment has controls for SOx and particulate matter (PM). The preliminary BARCT assessment for this category was presented in Working Group Meeting #2 on June 14, 2018 and the final assessment was presented during Working Group Meeting #12 held on July 17, 2020. There are no specific South Coast AQMD regulatory requirements for the petroleum coke calciner beyond the requirements in RECLAIM. BARCT assessments were conducted for the petroleum coke calciner in 2005 and 2015 as part of the RECLAIM program which established NOx emissions limits of 30 ppmv and 10 ppmv, respectively. The next section will summarize the BARCT assessment for petroleum coke calciner. The complete BARCT assessment is included in Appendix C.

NOx Limits that Represent BARCT

Table below summarizes the petroleum coke calciner NOx concentration limits demonstrated to be technically feasible and cost-effective (see Appendix C for the detailed analysis).

Table 2-19. Summary of BARCT Assessment for Petroleum Coke Calciner

Equipment Category[1]	Assess South Coast AQMD Regulatory Requirements	Assess Emission Limits of Existing Units	Assess Other Regulatory Requirements	Assess Pollution Control Technologies	Initial BARCT Emission Limit
Petroleum Coke Calciner	10 ppmv	65 –85 ppmv	N/A	5 ppmv	5 ppmv

(1) NOx limits are corrected to 3% oxygen

Interim Limits

Interim limit for the petroleum coke calciner is based on current operating conditions. PR 1109.1 will include a NOx interim limit of 85 ppmv and a CO interim limit of 2,000 ppmv at three percent oxygen, with a 365-day averaging period.

Averaging Times

PR 1109.1 establishes a 365-day rolling averaging time due to specific challenges of the petroleum coke calciner, such as: variability with the feed which affect NOx emissions; the petroleum coke calciner is a process unit and not an individual piece of combustion equipment; response times may be lower; and multiple pollutants need to be addressed. To ensure short-term NOx limits remain low, staff is also proposing a short-term NOx limit of 10 ppmv at three percent oxygen with a 7-day rolling average. This short-term limit will account for process variations in day-to-day operation of the petroleum coke calciner.

Carbon Monoxide Limits

PR 1109.1 establishes a 2,000 ppmv CO limit for the petroleum coke calciner. This limit is consistent with the existing permit limit for this unit.

Emission Limit Summary

The table below summarizes the emission limits in PR 1109.1 for petroleum coke calciner. There are no conditional limits for the petroleum coke calciner because achieving BARCT of 5ppmv has been determined to be cost-effective.

Table 2-20. PR 1109.1 Emission Limits for Petroleum Coke Calciner

PETROLEUM COKE CALCINERS		
NOx (ppmv)	CO (ppmv)	Rolling Averaging Time
3% O_2 Correction		
5	2,000	365-day
10		7-day

Table 2-21. Interim NOx Emission Limits for Petroleum Coke Calciner

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time
Petroleum Coke Calciner	85	2,000	3	365-day

FLUID CATALYTIC CRACKING UNITS (FCCUs) BARCT ASSESSMENT

Background

There are five refineries that operate five FCCUs in the South Coast AQMD: Torrance, Chevron, Tesoro Refinery, Phillips 66, and Ultramar (Valero Refinery). The initial BARCT assessment for this category was presented in Working Group Meeting #2 on June 14, 2018. Initial BARCT assessment was completed and presented during Working Group Meeting #11 held on May 21, 2020. A follow up BARCT reassessment was presented in Working Group Meeting #22 on June 30, 2021. The BARCT reassessment for this category was conducted to address units performing near the proposed BARCT limit. Three of the FCCUs currently have SCRs in operation for which the outlet NOx concentrations range from 1.2 to 10 ppmv; one of the three currently operates at a level under 2 ppmv NOx on an annual basis. The other two FCCUs currently operate with no NOx controls and permit limits vary from 20 to 40 ppmv NOx; the outlet NOx concentrations range from 14 to 32 ppmv. The next section will summarize the BARCT assessment for FCCUs. The complete BARCT assessment is included in Appendix D.

NOx Limits that Represent BARCT

The table below summarizes the NOx concentration limits that were demonstrated to be technically feasible and cost-effective for the FCCU category (see Appendix D for the detailed analysis).

Table 2-22. Summary of BARCT Assessment for FCCU

Equipment Category[1]	Assess South Coast AQMD Regulatory Requirements	Assess Emission Limits of Existing Units	Assess Other Regulatory Requirements	Assess Pollution Control Technologies	Initial BARCT Emission Limit
FCCU(1)	2 ppmv	1.2 – 32 ppmv	40 – 125 ppmv	2 ppmv	2/5 ppmv

(1) NOx limits are corrected to 3% oxygen.

Conditional Limit

PR 1109.1 will include a conditional limit for the FCCU category due to the high cost-effectiveness of some units. Of the five FCCUs, four currently have SCR NOx control or are in the permitting stage to install SCR. One unit is operating below the proposed BARCT NOx limit of 2 ppmv, one unit has been designed to meet 2 ppmv NOx, two are operating around 8 ppmv NOx and determined to not be cost effective to add further control to reduce to 2 ppmv, and one unit has no SCR NOx control but determined to be cost effective to install an SCR to achieve the proposed BARCT NOx limit of 2 ppmv. Cost for those two facilities operating around 8 ppmv NOx to upgrade and meet 8 ppmv NOx was approximately $1 million to $3 million, but to completely replace the SCR or add new technology to meet 2 ppmv ranged from $75 million to $220 million due to the advanced technology and engineering and design in addressing space constraints. While it would be cost effective for those facilities to meet 8 ppmv NOx at $12,000 per ton NOx reduced, it would not be cost effective, at $108,000 per ton NOx reduced, to achieve 2 ppmv NOx.

Depending on the technology selected it would be cost effective for the FCCU without an SCR to either install an SCR at $24,000 per ton of NOx reduced or alternative technology that could achieve multi-pollutant control at $46,000 per ton NOx reduced.

Interim Limit

Similar to the other equipment categories, staff established interim NOx limits based on the current emission levels or existing permit limits for FCCUs at 40 ppmv based on a 365-day average at three percent oxygen correction. As no facility currently operates above 40 ppmv, this interim limit will ensure no action (e.g., installation of control) would need to take place before the BARCT or conditional limit is met. In addition, it would place a not to exceed emission ceiling once facilities exit RECLAIM but before the BARCT or conditional limit is met.

Averaging Times

PR 1109.1 establishes a 365-day averaging time due to specific challenges of the FCCUs. FCCUs are very large complex units and generate NOx by coke burn off within the regenerator, not through the combustion of fuels. When an operator makes corrective actions in response to a NOx exceedance, the response time to the operational changes will not be seen for several hours. Staff is also proposing a short-term NOx limit of 5 ppmv at three percent oxygen with a 7-day rolling average to ensure that short-term NOx limits also remain low. This short-term limit will account for process variations in day-to-day operation of the FCCU.

Carbon Monoxide Limits

PR 1109.1 establishes a 500 ppmv CO at three percent oxygen correction limit for all FCCUs. Units with lower CO limits in existing permits will have to maintain the permitted limits.

Emission Limit Summary

NOx control technologies such as SCR and LoTOx™ are commercially available and it is technically feasible and cost-effective to achieve the proposed levels. The table below summarizes the emission limits in PR 1109.1 for an FCCU.

Table 2-23. PR 1109.1 Emission Limits for FCCU

FLUID CATALYTIC CRACKING UNITS (FCCUs)		
NOx (ppmv)	CO (ppmv)	Rolling Averaging Time
3% O_2 Correction		
2	500	365-day
5		7-day

Table 2-24. Conditional NOx and CO Emission Limits for FCCU

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time
FCCU	8	500	3	365-day
	16			7-day

Table 2-25. Interim NOx Emission Limits for FCCU

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time
FCCU	40	500	3	365-day

SUMMARY OF THE GAS TURBINE BARCT ASSESSMENT

Background

There is a total of 12 gas turbines operating at refineries in the South Coast AQMD. All gas turbines are in the combined-cycle mode, nine of which have duct burners and three have no duct burners. Gas turbines and duct burners emissions are controlled by a post-combustion control system such as SCR. Out of 12 gas turbine units, two units are entirely fired with natural gas and ten units are fired with other fuels (e.g., refinery fuel gas or refinery mixed gas). In the mixed fuel turbines, natural gas is used as primary fuel and refinery fuel gas is used as secondary fuel. Some refineries use a tertiary gas (e.g., butane) in the natural gas/refinery gas mix feed to power the gas turbines on an as-needed basis to ensure more reliable power production. The next section will summarize the BARCT assessment for gas turbines. The complete BARCT assessment is included in Appendix E.

NOx Limits that Represent BARCT

The table below summarizes the NOx concentration limits that were demonstrated to be technically feasible and cost-effective for the gas turbine category (see Appendix E for the detailed analysis).

Table 2-26. Summary of BARCT Assessment for Gas Turbine

Equipment Category[1]	Assess South Coast AQMD Regulatory Requirements	Assess Emission Limits of Existing Units	Assess Other Regulatory Requirements	Assess Pollution Control Technologies	Initial BARCT Emission Limit
Natural Gas	2 ppmv	1.1 – 1.8 ppmv	2 – 42 ppmv	2 ppmv	2 ppmv
Refinery Gas or Refinery Mixed Gas	2 ppmv	2.8 - 10 ppmv	9 - 50 ppmv	2 ppmv	2 ppmv

(1) Emission limits based on 15 percent oxygen correction.

Conditional Limit

Staff reviewed the BARCT assessment for the gas turbines fueled by natural gas which are operating close to the proposed BARCT limit and determined it would not be cost effective ($570,000 per ton of NOx reduced) for one unit with a NOx permit limit of 2.5 ppmv to take action and reduce down to 2 ppmv NOx. As such staff is proposing a conditional limit of 2.5 ppmv NOx and maintaining a BARCT NOx limit of 2 ppmv since it is cost effective ($15,400 per ton of NOx reduced) for the remaining units to install control and meet the 2 ppmv NOx.

Interim Limit

Similar to the other equipment categories, staff established interim NOx limits based on the current emission levels or existing permit limits for gas turbines at 20 ppmv based on a 365-day rolling average at 15 percent oxygen correction. As no facility currently operates above 20 ppmv NOx, this interim limit will ensure no action (e.g., installation of control) would need to take place before the BARCT or conditional limit is met. In addition, it would place a not to exceed emission ceiling once facilities exit RECLAIM but before the BARCT or conditional limit is met.

Averaging Times

Gas turbines will have a 24-hour rolling averaging time. For these units, staff initially proposed an 8-hour averaging time with respect to Norton Engineering's feedback that longer averaging times were necessary to achieve a 2 ppmv NOx limit. Due to the complexity and variability at facilities subject to PR 1109.1, longer averaging times were determined to be more appropriate. Norton Engineering's final report concluded the 8-hour average was too short to meet the 2 ppmv NOx limit and recommended a 24-hour averaging period. In order to retain the proposed 2 ppmv NOx limit, PR 1109.1 will include the 24-hour averaging time for gas turbines.

Carbon Monoxide Limits

PR 1109.1 establishes a 130 ppmv CO limit for all gas turbines, which is a typical limit found in current gas turbine permits. Any units with lower CO limits in existing permits will have to maintain the lower permitted limits, and units with higher limits may maintain the higher limit.

Emission Limit Summary

The table below summarizes the emission limits in PR 1109.1 for gas turbines.

Table 2-27. PR 1109.1 Emission Limits for Gas Turbines

GAS TURBINES			
Fuel Type	NOx (ppmv)	CO (ppmv)	Rolling Averaging Time
	15% O_2		
Natural Gas	2	130	24-hour
Gaseous Fuel other than Natural Gas	3		

Table 2-28. Conditional NOx and CO Emission Limits for Gas Turbines

Fuel Type	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time
Natural Gas	2.5	130	15	24-hour

Table 2-29. Interim NOx and CO Emission Limits for Gas Turbines

Fuel Type	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time
Natural Gas or Gaseous Fuel other than Natural Gas	20	130	15	365-day

SULFUR RECOVERY UNITS/TAIL GAS INCINERATORS BARCT ASSESSMENT

Background

There is a total of 16 SRU/TG incinerators operating in the South Coast AQMD, 13 without stack heaters and 3 with stack heaters. The initial BARCT assessment was presented in Working Group Meeting #2 on June 14, 2018 and a follow up BARCT reassessment was presented during Working Group Meeting #10 held on February 18, 2020. The next section will summarize the BARCT assessment for SRU/TG incinerators. The complete BARCT assessment for this category is included in Appendix F.

Since the inception of RECLAIM in 1993 until 2010, the South Coast AQMD did not set any BARCT standards for the SRU/TG incinerators. However, as part of the BARCT assessment, the 2015 RECLAIM BARCT NOx limit was determined as 2 ppmv at three percent oxygen . Currently no units have been retrofitted with post-combustion control and their annual average outlet NOx concentrations are ranging from 4 to 98 ppmv at three percent oxygen correction, depending on the type of fuel fired and operating conditions.

NOx Limits that Represent BARCT

The table below summarizes the NOx concentration limits that were demonstrated to be technically feasible and cost-effective for the SRU/TG incinerator category (see Appendix F for the detailed analysis). The 2 ppmv NOx limits in the table below under the Assessment of South Coast AQMD Regulatory Requirements reflects the RECLAM 2015 NOx BARCT Assessment. The RECLAIM BARCT assessment differs from the assessment conducted for PR 1109.1. The RECLAIM assessment concluded that certain high emitting units were cost effective to retrofit to 2 ppmv; however, the PR 1109.1 assessment included all of the SRU/TG Incinerators and it is not cost-effective to achieve 2 ppmv.

Table 2-30. Summary of BARCT Assessment for SRU/TG Incinerator

Equipment Category[1]	Assess South Coast AQMD Regulatory Requirements	Assess Emission Limits of Existing Units	Assess Other Regulatory Requirements	Assess Pollution Control Technologies	Initial BARCT Emission Limit
All Units	2 ppmv	4 – 74 ppmv	27 ppmv	2 ppmv	30 ppmv

(1) Emission limits based on 3 percent oxygen correction.

Conditional Limit

Staff is not proposing a conditional limit for SRU/TG incinerators because there are no high-cost outliers in the Class and Category.

Interim Limit

Similar to the other equipment categories, staff established an interim NOx limit based on the current emission levels or existing permit limits for SRU/TG Incinerators at 100 ppmv based on a 365-day rolling average at 3percent oxygen. As no facility operates this unit above 100 ppmv NOx, this interim limit will ensure no action (e.g., installation of control) would need to take place before the BARCT limit is met. In addition, it would place a not to exceed emission ceiling once facilities exit RECLAIM but before the BARCT limit is met.

Averaging Times

For SRU/TG incinerators, the proposed rolling averaging time in PR 1109.1 is 24 hours based on Norton Engineering's recommendation. Staff initially proposed an 8-hour averaging time but later decided to extend the averaging time to 24 hours per Norton Engineering's recommendation for a longer averaging time in order to give the refineries the ability to diagnose an abnormal operational problem and take the necessary corrective action(s) before an exceedance occurs. Units that do not operate with a CEMS will have to demonstrate compliance based on a source test that cannot exceed 2 hours.

Carbon Monoxide Limits

PR 1109.1 establishes a 400 ppmv CO at 3 percent oxygen limit for SRU/TG incinerators. Units with lower CO limits in existing permits will have to maintain the permitted limits, and units with higher limits can maintain their permit limits.

Emission Limit Summary

The table below summarizes the emission limits in PR 1109.1 for SRU/TG incinerators. Nine units out of 16 need to retrofit based on the proposed BARCT NOx limit. Achieving 2 or 5 ppmv with

SCR and LoTOx™ technologies were demonstrated to be technically feasible but not cost-effective.

Table 2-31. PR 1109.1 Emission Limits

SULFUR RECOVERY UNITS/TAIL GAS INCINERATORS		
NOx (ppmv)	CO (ppmv)	Rolling Averaging Time
3% O_2		
30	400	24-hour

Table 2-32. Interim NOx Emission Limits for SRU/TG Incinerator

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time
SRU/TG Incinerators	100	400	3	365-day

SUMMARY OF THE FLARE AND VAPOR INCINERATOR BARCT ASSESSMENT

Background

There is a total of 14 flares and vapor incinerators operating in the South Coast AQMD, including one small open flare and 13 vapor incinerators, which include afterburners, incinerators, and thermal oxidizers. Since the units in this category are very small (1-30 MMBtu/hr), installing a SCR control technology is not cost-effective. The best NOx control option is burner control. Staff evaluated similar-sized units from the Rule 1147 universe to assess technical feasibility of 20 ppmv NOx level. Thermal oxidizers at refineries operate similarly to units at other facilities that are primarily used for VOC control. Source test results demonstrate that ULNB for thermal oxidizers can achieve 20 ppmv NOx level. Also, there is only one open flare in the PR1109.1 universe. Open flares cannot be retrofitted with LNB or ULNB; therefore, staff considers replacement with a low-NOx flare (20 ppmv or 0.025 pounds/MMBtu) to be the best option for these flares. The next section will summarize the BARCT assessment for flares and vapor incinerators. The complete BARCT assessment is included in Appendix G.

Proposed BARCT NOx Emission Limit for Flare and Vapor Incinerator

The table below summarizes the NOx concentration limits that were demonstrated to be technically feasible and cost-effective for the flare and vapor incinerator category (see Appendix G for the detailed analysis).

Table 2-33. Summary of NOx BARCT Assessment for Flare and Vapor Incinerator

Equipment Category[1]	Assess South Coast AQMD Regulatory Requirements	Assess Emission Limits of Existing Units	Assess Other Regulatory Requirements	Assess Pollution Control Technologies	Initial BARCT Emission Limit
Afterburners, Vapor Incinerators, and Thermal Oxidizers	N/A	8 - 90 ppmv	20 ppmv	20 ppmv	20 ppmv
Flares	N/A	130 lbs/MMscf	Replacement with 20 ppmv flare (0.025 lbs/MMBtu) if throughput capacity >5%	20 ppmv	20 ppmv

(1) Emission limits based on 3 percent oxygen correction.

Conditional Limit

Staff is not proposing a conditional limit for flares; however, based on staff's review of the BARCT assessment for the vapor incinerators which are operating close to the proposed BARCT limit and determined it would not be cost-effective ($100,000 – $500,000 per ton of NOx reduced) for four units to take action and reduce down to 30 ppmv NOx. As such staff is proposing a conditional limit of 40 ppmv NOx and maintain a BARCT NOx limit of 30 ppmv since it is cost effective for the remaining units to replace burners and meet the 30 ppmv.

Interim Limit

Similar to the other equipment categories, staff established interim NOx limits based on the current emission levels or existing permit limits for vapor incinerators at 110 ppmv and flares at 105 ppmv based on a 365-day average at 3 percent oxygen. No facility currently operates above the respective interim NOx limits, ensuring no action (e.g., installation of control) would need to take place before the BARCT or conditional limit is met. In addition, it would place a not to exceed emission ceiling once facilities exit RECLAIM but before the BARCT or conditional limit is met.

Averaging Times

PR 1109.1 includes a 24-hour rolling average for vapor incinerators which will only apply to a few larger units with a CEMS. All other units will have to demonstrate compliance based on a source test that cannot exceed 2 hours.

Carbon Monoxide Limits

PR 1109.1 establishes a 400ppmv CO limits for all flares and incinerators. Any units with lower CO limits in existing permits will have to maintain the permitted limits, and units with higher limits may maintain the higher limit.

Emission Limit Summary

The table below summarizes the emission limits in PR 1109.1 for flares and incinerators.

Table 2-34. PR 1109.1 Emission Limits

FLARES		
NOx (ppmv)	CO (ppmv)	Rolling Averaging Time
3% O_2 Correction		
20	400	2-hour
VAPOR INCINERATORS		
NOx (ppmv)	CO (ppmv)	Rolling Averaging Time
3% O_2 Correction		
30	400	24-hour

Table 2-35. Conditional NOx Emission Limits for Vapor Incinerator

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time
Vapor Incinerators	40	400	3	2-hour

Table 2-36. Interim NOx Emission Limits for Vapor Incinerator

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time
Flares	105	400	3	365-day
Vapor Incinerators	110	400	3	365-day

AVERAGING TIME DISCUSSION

Averaging time could have a direct impact on the level of complexity and the cost of an emission control unit. Lower averaging times will increase the complexity and cost of an emission control system (e.g., SCR) by limiting the fluctuations in controlled NOx emissions; therefore, requiring more consistent NOx emissions. To propose an averaging time that meets the technical feasibility and cost-effectiveness requirements in the BARCT assessment, short term NOx emission fluctuations have been evaluated for each class and category in PR 1109.1. These short-term emission fluctuations occur during the unit's normal operation and should be separated from startup, shutdown, and malfunction events.

To examine the impact of averaging time in more detail, the following simplified equation can be derived:

$$T_{fluct} = (E_{BARCT} \times T_{avg} \times DM) / \left[E_{fluct} - E_{BARCT}(1 - DM)\right]$$

Where T_{fluct} (hours) represents the allowable period that NOx emission fluctuation can occur before exceeding the BARCT NOx limit, E_{BARCT} (ppmv) represents the BARCT NOx limit assigned for the class or category, T_{avg} (hours) represents the assigned averaging time, and E_{fluct}

(ppmv) represents the current NOx emission fluctuation. The design margin, DM (fractional value), represents a "margin" that is generally applied to the design of equipment to ensure it can meet the guaranteed value (i.e., a factor of safety applied to the design). A typical design margin for refinery equipment is 10% (DM = 0.1), this means that for an SCR with a 2 ppmv guaranteed NOx emission limit, the equipment has the capability to run at NOx emission levels in the 1.8 ppmv range. If a fluctuation occurs and the NOx emission level increases to E_{fluct}, there is a finite period the refinery can take action in order to correct operation and get the equipment back to the 1.8 ppmv range before the BARCT NOx limit is exceeded.

Based on Norton Engineering's recommendation, two averaging times for 2 ppmv BARCT NOx limit with a 10 percent design margin have been compared:

Table 2-37. Demonstration of the Impact of Different Averaging Times on Emission Limits

Averaging Time (hour)	Time to make corrective action (min)	Fluctuation limit (E_{fluct}, ppmv)	Conclusion
2	15	3.4	Does not provide a suitable time period to diagnose an equipment malfunction
	60	2.2	
24	15	21	Reasonable time period to take action or diagnose an equipment failure before the fluctuation time is exceeded
	60	6.6	

Therefore, based on Norton Engineering's recommendation, staff proposed a 24-hour averaging time for units greater than or equal to 40 MMBtu/hour.

THIRD PARTY CONSULTANT ASSESSMENTS

Fossil Energy Research Corporation (FERCo) and Norton Engineering Consultants (NEC) presented the summary of their technical review and recommendations at Working Group Meeting #16 on December 10, 2020. The written reports of their findings and recommendations are included in the Appendices of the staff report. Staff's BARCT assessment was adjusted in accordance with the recommendations from each consultant.

Norton Engineering Consultants Assessment

Norton Engineering conducted an independent review of current BARCT for stationary source categories identified by staff. Norton Engineering also assisted staff with several technical recommendations for difficult or specialized units with unique arrangements such as the SMR heater with integrated gas turbine and petroleum coke calciner. These were provided to staff in separate smaller individual reports or write-ups. Norton Engineering also provided input on recommended averaging times for each source category based on the initial proposed BARCT

NOx limits. Staff's final BARCT recommendations are reflective of Norton Engineering's comments. Norton Engineering's NOx BARCT Analysis Review can be found on the South Coast AQMD webpage.

Norton Engineering also conducted a review of the second cost submission submitted by the facilities on March 12, 2021, which was used by staff to revise the cost-effectiveness. Norton Engineering met with several technology vendors to understand the current state of both NOx combustion/source control and post-combustion control and is summarized in the table below. The table summarizes the most common techniques employed in controlling NOx emissions in refinery combustion equipment along with typical NOx levels that can be expected provided specific installation.

Table 2-38. Norton Engineering's Summary of NOx Control Techniques

Table 3.3-1: Assessment of NOx control technologies for proposed Rule 1109.1

Technology	New install applying BACT	Retrofit where the conditions are…			Comments
		Most favorable for the installation	Typical for the installation	Unfavorable for the installation	
Fuel switching to NG	% NOx reduction = 100 x {1 – 1 / [1 + 0.625 x (mol/mol H_2 before switch)] }				Approximation Independent of technology
FGR with staged fuel burner (1)	30 ppmv	> 30 ppmv	< 40 ppmv	< 50 ppmv	Typically applied to boilers
ULNB (1)	15 ppmv	< 20 ppmv	< 35 ppmv	< 50 ppmv	Commercially available ULNBs
Next generation ULNB (1)	> 5 ppmv		< 10 ppmv		Commercial demonstration underway with Clearsign
Flameless combustion (1)	5 ppmv	–	–	–	One demonstration unit on a small heater
SNCR with 5 ppmv NH_3 slip	70% NOx reduction maximum	High inlet NOx (>100 ppmv): 40 to 50% NOx reduction			Limited application due to geometrical considerations
		Low inlet NOx (50 to 100 ppmv): 20 to 40% NOx reduction			
SCR	2 ppmv	2 ppmv			Multiple catalyst beds required
Lo-TOx	10 ppmv	10 ppmv	≤ 90% NOx Reduction	< 50% NOx reduction	Wet Gas Scrubber (WGS) required downstream

(1) Fuel assumed to be RFG unless noted otherwise

Assessment of Control Technologies

Process Heaters and Boilers

Norton Engineering's assessment of control technologies coincides with staff's assessment that in some cases combination of source and post-combustion control are required to meet BARCT levels. Combination control is the most effective way of reducing NOx for the process heaters and boilers categories. Staff initially concluded that 2 ppmv NOx is technically feasible with a combination of LNB or ULNB and SCR, but Norton Engineering indicated that achieving a 2 ppmv NOx with just an SCR is also possible and will require the unit to:

- Operate at low superficial gas velocity (<10 ft/s),

- Operate within the optimal temperature window,
- Install multiple SCR catalyst beds (2 minimum) with an ammonia destruction bed, and
- Employ multiple ammonia injection grids between catalyst beds for uniform distribution of ammonia.

This recommendation by Norton Engineering was used by staff as an alternative pathway to achieve 2 ppmv NOx when stakeholders expressed concern over the ability of heaters to accept a ULNB retrofit. Staff also initially assumed that LNB can achieve 40 ppmv NOx and used that as the upper NOx limit when calculating cost-effectiveness. However, Norton Engineering's assessment concluded that under unfavorable conditions, an LNB can have NOx emissions up to 50 ppmv. Staff revised the cost-effectiveness calculation using 50 ppmv NOx as the upper limit for burner control technology.

*Steam Methan***e** *Reformer (SMR) Heaters and SMR Heaters with Gas Turbine*
For this heater category, staff relied on Norton Engineering's recommendation that the lowest BARCT limit that could be set is 5 ppmv NOx with the expectation that multiple SCR catalyst beds will be required in most cases. Norton Engineering stated that high hydrogen content in the fuel will result in high combustion zone temperature and fuel gas composition swings due to the pressure swing adsorption cycle can impact NOx.

Sulfuric Acid Plant Furnaces
Norton Engineering's conclusion for the sulfuric acid furnaces agrees with staff's conclusion. Both Norton Engineering and staff concluded that post-combustion options are not well suited for this application due to the high sulfur and low temperatures which can potentially form ammonium bisulfate and plug or foul the catalyst. LoTOx™ will require modification or additional changes to the existing scrubber system. Norton Engineering supports staff's proposed BARCT NOx limit of 30 ppmv with custom designed burners.

Fluid Catalytic Cracking Unit (FCCU)
Norton Engineering's assessment for the FCCU category concluded that staff's BARCT proposal of 2 ppmv NOx is technically feasible with a multi-bed SCR system. The FCCU regenerator operates at temperatures where thermal NOx formation is low and the primary source of NOx originates from nitrogen species in the feed, or coke on catalyst, which is analogous to fuel NOx. Heavily hydrotreating the feed to the FCCU can reduce nitrogen species in order to reduce NOx emissions. Other control options include regenerator catalyst additives that reduce NOx, which must be used in conjunction with SCR.

Gas Turbines (firing natural gas and other gaseous fuels)
NOx controls for gas turbines are dry low NOx (DLN) combustors and SCR. These are the two most effective NOx controls for gas turbines. Norton Engineering agrees that the BARCT NOx limit of 2 ppmv is achievable with new SCR designs and 50% more catalyst than the existing SCR.

Petroleum Coke Calciner
Norton Engineering's assessment agrees with staff's assessment that post-combustion control is the only practical solution for NOx reduction to the proposed BARCT limit for the petroleum coke calciner. The petroleum coke calciner has a high combustion zone with an adiabatic chamber, so source control options, such as LNB, are limited. Norton Engineering also identified three post-combustion control options that can be considered for the petroleum coke calciner:

1. SCR, which requires an optimal temperature 650 to 750 ºF and may require stack flue gas reheat with duct burners;
2. LoTOx™, which requires a wet scrubber and ozone generation equipment; and
3. UltraCat™, which has similar requirements as SCR, but has limited field usage and requires a large plot area.

Sulfur Recovery Units/Tail Gas (SRU/TG) Incinerators

Norton Engineering's assessment concludes that NOx emissions from SRU/TG incinerators are the result of NOx concentration in the inlet vapor. Norton Engineering agrees with staff's assessment that the only practical solution is advanced custom designed burner upgrades or retrofits which can achieve 30 ppmv NOx. Commercially available ULNB are not well suited for this application. SCR is impractical for this category due to low temperature and high SOx which can form ammonium bisulfate and foul the catalyst. LoTOx™ is a potential option if space is available downstream.

Averaging Times

Norton Engineering recommended a 24-hour averaging time for any unit with a CEMS. The 24 hour is recommended based on detection of meaningful fluctuation and time for operations to diagnose and resolve problems. Staff revised the proposed averaging times for units with CEMS based on the recommendation.

Fossil Energy Research Corporation Assessment

FERCo conducted site visits to the five major refineries, Chevron, Marathon (Tesoro Refinery), Phillips 66, Torrance, and Valero, to evaluate and discuss facility constraints and challenges of implementing SCR on specific refinery systems. The main concern refinery stakeholders frequently raised to staff was the issue of space and the ability to install post-combustion control. The goal of the FERCo facility visits was to observe first-hand these facility concerns. FERCo met with facility representatives and toured the facilities. In addition, FERCo and facility staff discussed any challenges of implementing SCR on specific refinery systems which included a review of drawings of on-going SCR work or suggested configuration modifications to improve performance. FERCo also assisted staff in the cost evaluation by evaluating the two main source of cost estimates: revised U.S. EPA SCR cost model and unit-specific costs from facilities. FERCo also reviewed staff's methodology in revising the U.S. EPA SCR cost model which involved using refinery specific cost data to modify the cost relationships making it more representative of the refining industry. FERCo's South Coast Air Quality Management District Rule 1109.1 Study Final Report can be found on the South Coast AQMD webpage.

Factors Affecting NOx Control Costs

Based on the site visits, FERCo concluded that all the facilities exhibited space limitations to varying degrees. Not all open space that surrounds a unit is available for an SCR system, as open space may be necessary for maintenance work. Despite the space limitations, some facilities have devised several workarounds such as vertical SCR orientation, running ductwork over existing roadways, and replacement of air heaters with SCR reactors. In addition, FERCo also identified that the locations or sites for SCR installations may hold many unknowns such as electrical capacity for the SCR and uncertainties that can complicate foundation work such as underground pipes. Based on these complexity factors, FERCo confirmed that the installation cost can significantly exceed that of the NOx equipment and can exceed the equipment cost by a factor of at least 2.5. Based on FERCo's assessment, staff has agreed to accept all facility provided cost data in the cost-effectiveness analysis. If a facility provided cost for a specific unit, staff used the facility cost data. Furthermore, staff used all the facility cost to revise the U.S. EPA SCR cost model.

Upgrading Existing SCR Reactors

FERCo's assessment also determined that existing SCR systems are not designed for high NOx removal (>90% reduction), FERCo identified several key SCR issues that can be improved upon to achieve better performance:

- Catalyst activity or how active the material is in reducing NOx;
- Reactor potential, the ability of the catalyst bed to reduce NOx, and needed catalyst volume; and
- Ammonia/NOx distribution which describes the uniformity across the catalyst and mechanism by which ammonia is injected. This is characterized by root mean squared (RMS) or deviation of ammonia/NOx distribution entering the catalyst – higher NOx removal requires lower RMS.

FERCo also discussed the importance of AIG tuning in optimizing ammonia/NOx distribution by providing an example of a recent project where additional NOx reduction was achieved simply by tuning the system.

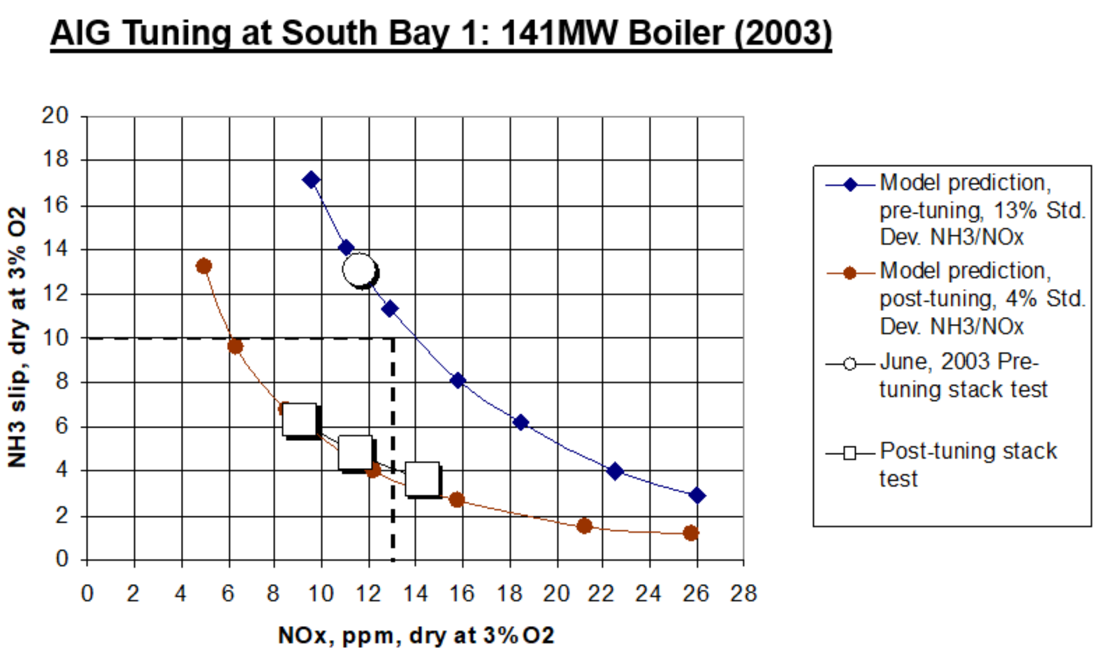


Figure 11. AIG Tuning Optimization

Changes to the AIG may include any of the following changes:

- Resizing existing AIG orifices
- Redesigning the AIG

- Adding flow control valves
- Moving AIG to different location
- Adding a static mixer

According to FERCo all these changes are relatively minor, involving at most piping modifications. Overall, upgrading of existing SCR systems to comply with Rule 1109.1 are estimated to cost between 10 and 35% of the cost of a new SCR. FERCo anticipates that only minor modifications will likely be needed since all the SCR infrastructure is already in place. FERCo also recommended that replacing or adding additional SCR catalyst can help improve removal efficiency. Staff has incorporated this recommendation in establishing the criteria for the conditional limits for units in the process heater and boilers category. These units will be allowed to upgrade their existing SCR system to reduce overall cost to a facility. It is more cost-effective to upgrade a SCR than replace with a brand-new system.

FERCo also stated that to further achieve maximum emission reductions, a combination of LNB/ULNB and SCR will be necessary for devices with high NOx emissions. FERCo also suggested that potentially splitting the SCR catalyst volume between two reactors in series (each housing to be equal to one-half of the total catalyst volume) where additional mixing of the flue gas stream could be accomplished.

U.S. EPA Cost Model

FERCo also reviewed staff's approach to modifying the U.S. EPA SCR cost model and concluded that it can be used to provide budgetary costs. FERCo stated that the SCR cost model be improved by improving the methodology to estimate required catalyst volumes based on current catalyst technology available which is minor when compared to the overall installation costs.

CHAPTER 3 SUMMARY OF PROPOSALS

INTRODUCTION

PR 1109.1 establishes NOx and CO concentration limits for combustion equipment located at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries. All the Facilities subject to PR 1109.1 are currently in RECLAIM and will be required to meet the limits in PR 1109.1 while in RECLAIM and after the facility transitions out of RECLAIM and becomes a Former RECLAIM Facility. The proposed rule includes provisions and requirements consistent with other NOx RECLAIM landing rules as well as provisions specific to Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries. The following information describes the structure of PR 1109.1 and explains the requirements in each of the provisions.

PROPOSED RULE STRUCTURE

(a)	Purpose
(b)	Applicability
(c)	Definitions
(d)	Concentration Limits
(e)	Interim Concentration Limits
(f)	Compliance Schedule
(g)	B-Plan and B-Cap Requirements
(h)	I-Plan Requirements
(i)	I-Plan, B-Plan, and B-Cap Submittal and Approval Requirements
(j)	Time Extensions
(k)	CEMS Requirements
(l)	Source Test Requirements
(m)	Diagnostic Emission Checks
(n)	Monitoring, Recordkeeping, and Reporting Requirements
(o)	Exemptions
(Attachment A)	Supplemental Calculations
(Attachment B)	Calculation Methodology for the I-Plan, B-Plan, And B-Cap
(Attachment C)	Facilities Emissions – Baseline and Targets
(Attachment D)	Units Qualify for Conditional Limits in B-Plan and B-Cap

PROPOSED RULE 1109.1

SUBDIVISION (a) – PURPOSE

The purpose of this rule is to reduce emissions of NOx, while not increasing CO emissions, from combustion equipment at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries. As discussed in Chapter 1, PR 1109.1 is needed to transition Petroleum Refineries and Facilities With Related Operations to Petroleum Refineries from RECLAIM to a command-and-control regulatory structure. PR 1109.1 is a command-and-control rule that is designed to satisfy requirements to establish BARCT under Health and Safety Code Section 40920.6 which implements AB 617.

SUBDIVISION (b) – APPLICABILITY

PR 1109.1 applies to combustion equipment at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries, including Asphalt Plants, Biofuel Plants, Hydrogen Production Plants, Petroleum Refineries, facilities that operate Petroleum Coke Calciners, Sulfuric Acid Plants, and Sulfur Recovery Plants. The provisions of PR 1109.1 apply to Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries while in RECLAIM and after they transition out of RECLAIM. Combustion equipment which are subject to this rule are categorized as Boilers, Flares, Fluid Catalytic Cracking Units, Gas Turbines, Petroleum Coke Calciners, Process Heaters, Steam Methane Reformer Heaters, Sulfuric Acid Furnaces, Sulfur Recovery Units/Tail Gas Incinerators, and Vapor Incinerators.

SUBDIVISION (c) – DEFINITIONS

Definitions in PR 1109.1 are incorporated to define equipment, fuels, and other rule terms. Below are some key definitions that are used in PR 1109.1. To provide clarity, definitions are used in the proposed rule and this staff report as a proper noun to better distinguish defined terms from common terms. Refer to PR 1109.1 for a complete list of definitions.

PR 1109.1 includes a definition for “Facilities With The Same Ownership” which is used in a couple of key provisions for alternative compliance plans and certain provisions for interim emission limits.

- FACILITIES WITH THE SAME OWNERSHIP means Facilities and their subsidiaries, Facilities that share the same board of directors, or Facilities that share the same parent corporation.

At the time of this staff report, the following are the PR 1109.1 Facilities With The Same Ownership:

Table 3-1. Facilities With The Same Ownership

Owner	Facility	Facility ID
Marathon Petroleum Company/Tesoro Refining and Marketing, LLC (Marathon)	Tesoro – Carson	174655
	Tesoro – Wilmington	800436
	Tesoro – Sulfur Recovery Plant	151798
	Tesoro – Petroleum Coke Calciner	174591
Phillips 66	Phillips 66 – Carson	171109
	Phillips 66 – Wilmington	171107
Valero	Ultramar/Valero Wilmington	800026
	Valero Asphalt Plant	800393

The definition of “Unit” was included to streamline the rule language.

- UNIT means, for the purpose of this rule, any Boilers, Flares, FCCUs, Gas Turbines, Petroleum Coke Calciners, Process Heaters, SMR Heaters, Sulfuric Acid Furnaces, SRU/TG Incinerators, or Vapor Incinerators that requires a South Coast AQMD permit and is not required to comply with a NOx concentration limit in another South Coast AQMD Regulation XI rule.

SUBDIVISION (d) – CONCENTRATION LIMITS

This subdivision establishes the proposed BARCT NOx Concentration Limits and Corresponding CO Concentration Limits for combustion equipment at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries. PR 1109.1 Table 1 lists the NOx Concentration Limits and Corresponding CO Concentration Limits for each class and category of equipment subject to PR 1109.1 and identifies the corresponding rolling averaging time and percent of oxygen as the basis for emissions measurement or calculation. Averaging times must be calculated as established in Attachment A of PR 1109.1 for any unit that operates with CEMS. All averaging times based on CEMS are rolling averages and are established for different types of equipment in Table 1 and Table 2 of PR 1109.1. Units that must demonstrate compliance with a source test are required to demonstrate compliance based on the time specified in the approved source test protocol as discussed in subdivision (l). Subdivision (f) lays out the compliance dates for a Facility complying with the NOx and CO Concentration Limits in Table 1.

NOx CONCENTRATION LIMIT(S) means the NOx concentration limit at the applicable percent O_2 correction and averaging period specified in Table 1, Table 2, Table 3, or Table 5 – Maximum Alternative BARCT NOx Concentration Limits for a B-Cap (Table 5).

CORRESPONDING CO CONCENTRATION LIMIT(S) means the CO concentration limit, that corresponds to the referenced NOx Concentration Limit, at the applicable percent O_2correction and averaging period specified in Table 1, Table 2, or Table 3 – Interim NOx and CO Concentration Limits (Table 3).

Table 3-2. PR 1109.1 Table 1 – NOx and CO Concentration Limits

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers <40 MMBtu/hour	Pursuant to subparagraphs (d)(2)(A) and (d)(2)(B)	400	3	24-hour
Boilers ≥40 MMBtu/hour	5	400	3	24-hour
FCCU	2	500	3	365-day
	5			7-day
Flares	20	400	3	2-hour
Gas Turbines fueled with Natural Gas	2	130	15	24-hour
Gas Turbines fueled with Gaseous Fuel other than Natural Gas	3	130	15	24-hour
Petroleum Coke Calciner	5	2,000	3	365-day
	10			7-day
Process Heaters <40 MMBtu/hour	Pursuant to subparagraphs (d)(2)(A) and (d)(2)(C)	400	3	24-hour
Process Heaters ≥40 MMBtu/hour	5	400	3	24-hour
SMR Heaters	5	400	3	24-hour
SMR Heaters with Gas Turbine	5	130	15	24-hour
SRU/TG Incinerators	30	400	3	24-hour
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	30	400	3	24-hour

[1] Averaging times apply to Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule; compliance for Units without a certified CEMS shall be demonstrated pursuant to paragraph (l)(1).

Proposed NOx Limits for Boilers and Process Heaters with a Rated Heat Input Capacity Less than 40 MMBtu/hr – Paragraph (d)(2)

PR 1109.1 establishes NOx Concentration Limits for Boilers and Process Heaters less than 40 MMBtu/hr in two steps. The averaging time, oxygen correction, and Corresponding CO Concentration Limit are specified in Table 1 and is the same for the applicable NOx Concentration

Limits to these Units in both steps. The compliance schedule for the two steps is addressed under the Compliance Schedule in Table 4. The NOx Concentration Limit for Boilers and Process Heaters less than 40 MMBtu/hr is:

- First Step: 40 ppmv for both Boilers and Process Heaters; then
- Second Step: 5 ppmv for Boilers and 9 ppmv for Process Heaters.

Conditional NOx Concentration Limits – Paragraph (d)(3)
PR 1109.1 provides alternative BARCT NOx limits for units which are currently operating at or below NOx Concentration Limits in Table 2 of PR 1109.1, shown as Table 3-3 below. This provision is designed to recognize that some units have existing pollution controls that are currently operating near the NOx Concentration Limits in PR 1109.1 Table 1, and it is not cost-effective to require replacement or installation of additional pollution controls for those Units. PR 1109.1 includes conditions that an owner or operator must meet if an owner or operator elects to meet the Conditional NOx Concentration Limits and Corresponding CO Concentration Limits in Table 2, in lieu of the NOx Concentration Limits and Corresponding CO Concentration Limits in Table 1.

Table 3-3. PR 1109.1 Table 2 – Conditional NOx and CO Concentration Limits

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers >110 MMBtu/hour	7.5	400	3	24-hour
FCCUs	8	500	3	365-day
	16			7-day
Gas Turbines fueled with Natural Gas	2.5	130	15	24-hour
Process Heaters ≥40 – ≤110 MMBtu/hour	18	400	3	24-hour
Process Heaters >110 MMBtu/hour	22	400	3	24-hour
SMR Heaters	7.5	400	3	24-hour
Vapor Incinerators	40	400	3	2-hour

[1] Averaging times apply to Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule; compliance for Units without a certified CEMS shall be demonstrated pursuant to paragraph (l)(1).

PR 1109.1 allows owners or operators to use PR 1109.1 Table 2 Conditional NOx Concentration Limits in lieu of meeting Table 1 NOx Concentration Limits. The owner or operator must meet all of the conditions specified under paragraph (d)(3) and meet the permit submittal and compliance dates under paragraph (f)(3), including submitting a permit application by June 1, 2022.

Conditions for Using Conditional NOx Concentration Limits
Since the Table 2 NOx Concentration Limits can be used in lieu of Table 1 NOx Concentration Limits to establish the Facility BARCT Emission Target under the alternative BARCT compliance

plans, staff realized it was critical to establish conditions to ensure only those Units that were operating near the NOx Concentration Limits in Table 1 and would have high cost-effectiveness values to meet NOx Concentration Limits in Table 1 are allowed to use the Conditional NOx Concentration Limits. Staff was also concerned that owners or operators could potentially install pollution controls and meet the Conditional NOx Concentration Limits instead of the more stringent Table 1 NOx limits and could create a "budget" of NOx emissions that could be used to have higher NOx concentration levels for other Units.

Under subparagraph (d)(3)(A), the first condition for a unit to be allowed a Table 2 conditional limit is that the Executive Officer has not issued a Permit to Construct on or after December 4, 2015 for the installation of a pollution control device. This condition is to prevent Units with currently installed pollution control devices, such as SCR, which can achieve the Table 1 NOx Concentration Limits, from electing to comply with Table 2 conditional limits. December 4, 2015 was selected as this is the date when Regulation XX – RECLAIM was amended to reduce or shave allocations. The analysis was based on a technical analysis that large boilers and heaters could achieve a NOx concentration of 2 ppmv. Staff believes that Units modified after this date should have been designed to achieve the proposed NOx limits in Table 1. Boilers and heaters greater than or equal to 40 MMBtu/hour installed with a modern SCR can achieve 5 ppmv NOx, if not lower. This condition will also ensure Units that can achieve significant NOx reductions in a cost-effective manner, are required to meet the NOx and CO Concentration Limits under Table 1 of PR 1109.1.

The next two conditions, subparagraphs (d)(3)(B) and (d)(3)(C), are that emission reduction projects for Process Heaters greater than or equal to 40 MMBtu/hour but less than or equal to 110 MMBtu/hour cannot have an emission reduction potential (referred to in the rule as "Unit Reductions" and calculated pursuant to Attachment B in the rule) of 10 tons per year or more, and emission reduction projects for Boilers or Process Heaters greater than 110 cannot have an emission reduction potential of 20 tons per year or more. The potential emission reductions are based on the difference of the baseline emissions and the Table 1 concentration limits, scaled to the baseline emissions.

The next two conditions, subparagraphs (d)(3)(D) and (d)(3)(E), are that the Unit must not have an existing permit limit at or below the Table 1 NOx Concentration Limits or have a Representative NOx Concentration that is at or below the Table 1 NOx Concentration Limits. These conditions will prevent Units that are achieving NOx emissions that meet the Table 1 NOx Concentration Limits from electing to comply with the conditional limits.

FACILITY BARCT EMISSION TARGET means the total mass emissions per facility calculated based on the applicable Table 1 NOx emission limits or Table 2 conditional NOx limits and the 2017 annual NOx emissions, or another representative year as approved by the Executive Officer.

The last condition, subparagraph (d)(3)(F), excludes any unit that has been decommissioned pursuant to paragraph (f)(10) from being eligible to use the conditional NOx limits in Table 2.

Gas Turbines – Paragraph (d)(4)

PR 1109.1 provides an alternative NOx concentration limit of 5 ppmv (corrected to 15 percent oxygen on a dry basis) based on a 24-hour rolling average, instead of the 2-ppmv and 3-ppmv NOx limits for Gas Turbines operating on natural gas and refinery gas, respectively, during natural gas curtailment periods. Natural gas curtailment occurs when there is a shortage in the supply of pipeline Natural Gas due to limitations in the supply or restrictions in the distribution pipelines by the utility that supplies Natural Gas. A shortage in Natural Gas supply that is due to changes in the price of Natural Gas does not qualify as a Natural Gas curtailment. Corresponding CO Concentration Limits for the Gas Turbines subject to this provision are the same as listed in Table 1 and Table 2 of PR 1109.1.

Units With Combined Stacks – Paragraph (d)(5)

Paragraph (d)(5) requires Units With Combined Stacks to meet the most stringent applicable Table 1 or Table 2 NOx Concentration Limit. Below are the criteria to determine which requirements apply to Units With Combined Stacks if one or more of the Units fall in a different size category as follows:

- If multiple Units are combined:
  - One Unit is >110 MMBtu/hr and the other are less → >110 MMBtu/hr
  - All Units are ≥40 – 110 MMBtu/hr → ≥40 – ≤110 MMBtu/hr
  - One Unit is ≥40 MMBtu/hr and the other Units are less → ≥40 – ≤110 MMBtu/hr

CO Concentration Limits – Paragraph (d)(6)

PR 1109.1 Table 1 and Table 2 establish CO concentration limits for each class and category of equipment. As discussed, the purpose of this rule is to reduce emissions of NOx from combustion equipment at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries, with no increase in the associated CO emissions. The CO emissions for the classes and categories of equipment listed in PR 1109.1 Table 1 and Table 2 are generally representative of CO concentration limits in permits and consistent with other rules regulating similar combustion equipment. This paragraph allows an owner or operator of a Unit that has a CO concentration limit established in a Permit to Operate or Permit Construct before the date of rule adoption, to meet the CO concentration limit in the Permit to Operate or Permit to Construct in lieu of the applicable Corresponding CO Concentration Limit. The CO permit limit can include an actual permit limit or a reference to South Coast AQMD Rule 407 – Liquid and Gaseous Air Contaminants.

An owner or operator with six or more units, have the option to use a B-Plan or B-Cap that will allow the selection of a NOx limit that may be higher than the NOx limits established in PR 1109.1. However, regardless of the NOx limit selected in a B-Plan or B-Cap, the owner or operator is required to meet the applicable CO concentration limit in Table 1 or Table 2, or as allowed under paragraph (d)(6).

SUBDIVISION (e) – INTERIM CONCENTRATION LIMITS

As discussed in Chapter 2, Interim NOx Concentration Limits are needed after Facilities transition out of RECLAIM and before the Unit meets the NOx limits in PR 1109.1 to ensure there is no backsliding and interference with attainment.

Interim NOx Concentration Limits (e)(1)

The interim NOx Concentration Limits in of PR 1109.1 applies to Facilities that elect to meet the Table 1 or Table 2 NOx Concentration Limits directly, all Units at a Facility that is complying with a B-Plan, and any Boiler or Process Heater less than 40 MMBtu/hour not included in a B-Cap. The approach for the interim Concentration Limits is different for owners or operators that select to comply with a B-Plan versus complying with a B-Cap. Owners or Operators that elect to comply with a B-Plan will be required to meet equipment specific interim NOx Concentration Limits or NOx emission rates. On the other hand, the owners or operators that elect to comply with the B-Cap are not held to the individual interim NOx Concentration Limits since those Facilities are operating under a facility-wide mass emissions cap. However, any Units outside of the B-Cap will be required to meet the interim NOx Concentration Limits upon exiting RECLAIM, before being subject to another NOx limits in PR 1109.1. The provision for the B-Cap is needed as PR 1109.1 allows operators to exclude Boilers and Process Heaters less than 40 MMBtu/hour from the B-Cap. Any unit that is not included in the mass emissions cap under the B-Cap, will be required to meet the Interim NOx Concentration limit under Table 3 of PR 1109.1 upon exiting RECLAIM.

Interim NOx and CO Concentration Limits – Table 3

PR 1109.1 includes interim NOx Concentration Limits that are based on permit limits and actual emissions data. Except for interim NOx Concentration Limits for Boilers and Process Heaters 40 MMBtu/hour and greater, all interim limits are a specific NOx concentration limit and are provided in Table 3 of PR 1109.1 and are presented below. All interim limits provide a 365-day averaging period which is proposed to minimize disruptions as Facilities transition out of RECLAIM.

Table 3-4. PR 1109.1 Table 3 – Interim NOx and CO Concentration Limits

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers and Process Heaters <6 MMBtu/hour[2]	60	400	3	365-day
Boilers and Process Heaters ≥6 MMBtu/hour and <40 MMBtu/hour[2]	40	400	3	365-day
Boilers and Process Heaters ≥40 MMBtu/hour	Pursuant to paragraph (e)(2)	400	3	365-day
Flares	105	400	3	365-day
FCCUs	40	500	3	365-day
Gas Turbines fueled with Natural Gas or Other Gaseous Fuel	20	130	15	365-day
Petroleum Coke Calciner	85	2,000	3	365-day
SMR Heaters	20[3]	400	3	365-day
	60[4]			365-day
SMR Heaters with Gas Turbine	5	130	15	365-day
SRU/TG Incinerators	100	400	3	365-day
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	110	400	3	365-day

1 Averaging times are applicable to Units with a CEMS and shall be calculated pursuant to Attachment A of this rule; compliance for Units without a certified CEMS shall be demonstrated pursuant to paragraph (l)(1).

2 Boilers and Process Heaters with a Rated Heat Input Capacity <40 MMBtu/hour that operate with a certified CEMS may comply with the NOx emission rate pursuant to paragraph (e)(2) in lieu of the NOx Concentration Limit in Table 3.

3 SMR Heaters equipped with post-combustion air pollution control equipment that was installed before [DATE OF ADOPTION].

4 SMR Heaters not equipped with post-combustion air pollution control equipment as of [DATE OF ADOPTION].

Interim Limits for Boilers and Process Heaters for Facilities Complying with Table 1 or Table 2, or a B-Plan – Paragraph (e)(2)

For Boilers and Process Heaters with a Rated Heat Input Capacity greater than or equal to 40 MMBtu/hour, staff found substantial variation in the NOx concentration levels with no definitive groupings of Units to establish a specific NOx concentration limit. For owners or operators under an approved B-Plan, upon exiting RECLAIM when the facility becomes a Former RECLAIM Facility, the owner or operator must meet a 0.03 pounds/MMBtu over a rolling 365-day average for all Boilers and Process Heaters that are greater than or equal to 40 MMBtu/hour and may include Boilers and Process Heaters that are less than 40 MMBtu/hour if they operate with a certified NOx CEMS. This provision would be effective on the day after the Facility becomes a Former RECLAIM Facility and calculated per Attachment A Section (A-2) of PR 1109.1. To demonstrate the rolling average the owner or operator will use the mass emissions from the prior 365 days, with emissions for 364 days to be based on emissions while the Facility was in RECLAIM and emissions for the 365th day will be based on the day the Facility became a Former RECLAIM facility. Subparagraph (e)(2)(B) requires subparagraph (e)(2)(A) to be implemented until the last Unit under this provision meets the final applicable NOx concentration limit in Table 1, Table2, or an approved B-Plan to ensure that as Units comply with the NOx concentration limit, the remaining units do not exceed the applicable threshold.

The calculation to determine a Facility's NOx levels is included in Attachment A Section (A-2) of PR 1109.1 and is as follows:

- Hour Mass Emissions (lbs/hour) Section (A-2.1)

  Sum the actual annual mass emissions of all Boilers and Process Heaters with a Rated Heat Input Capacity at or greater than 40 MMBtu/hour and any Boilers and Process Heaters with a Rated Heat Input Capacity less than 40 MMBtu/hour that operate a certified CEMS and divide by 8,760 hours for pounds per hour.

- Combined Maximum Rated Heat Input Capacity (MMBtu/hour) Section (A-2.2)

  Sum the combined maximum Rated Heat Input Capacity for all Boilers and Process Heaters with a Rated Heat Input Capacity at or greater than 40 MMBtu/hour and any Boilers and Process Heaters with a Rated Heat Input Capacity less than 40 MMBtu/hour that operate a certified CEMS.

- Interim Facility Wide NOx Emission Rate (lbs/MMBtu) Section (A-2.3)

  Divide the Hourly Mass Emissions in Section (A-2.1) by the combined Maximum Heat Input in Section (A-2.2) to determine the interim facility-wide NOx emission rate.

Interim Requirements for a Facility with a B-Cap – Paragraph (e)(3)

Facilities that elect to comply with a B-Cap will not be held to the NOx concentrations limits in Table 3 of PR 1109.1, with the exception of those Boilers and Process Heaters less than 40 MMBtu/hour that are not included in an approved B-Cap. Facilities under a B-Cap will be required to demonstrate on a daily bases, based a 365-day rolling average that they meet the Facility BARCT Emission Targets that are specified in subparagraph (h)(4)(D). If a facility exits RECLAIM before the implementation of the first Phase of an I-Plan, the emissions cap will be based on the Baseline NOx Emissions.

SUBDIVISION (f) – COMPLIANCE SCHEDULE

This subdivision establishes the implementation schedules for combustion equipment at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries to comply with PR 1109.1 requirements.

Compliance Schedule for Table 1 – Paragraph (f)(1)

This paragraph requires an owner or operator to submit a complete permit application to establish a NOx and Corresponding CO Limit in a permit on or before July 1, 2023. Owners or operators must meet the NOx and CO concentration limits in PR 1109.1 Table 1 from the date the Permit to Operate is issued or no later than 36 months after a Permit to Construct is issued, whichever is sooner. Operators with a Permit to Construct or a Permit to Operate that already has an enforceable NOx concentration limit consistent with Table 1 are not required to submit a permit application. This is the only compliance pathway for Facilities with less than six Units. For Facilities with six or more Units, PR 1109.1 provides this compliance pathway as well as an alternative implementation schedule under the I-Plan.

It should be noted several of the rule provisions require "a complete permit application" to be submitted. A complete permit application includes, but not limited to, all signed forms with all applicable fields filled in, applicable fees, and additional information needed by the Executive Officer to make a determination. This is different than a permit that has been "deemed complete", which is the formal determination the Engineering Division makes when confirming all information has been received to properly conduct their analysis to process the permit. There are existing rules which dictate the criteria for a complete permit application:

1. The preamble to Reg. II – List and Criteria Identifying Information Required Of Applicants Seeking A Permit To Construct From The South Coast Air Quality Management District;
2. Rule 210 – Permit to Construct; and
3. Rule 3003 – Applications.

A complete permit application includes, but is not limited to, all signed forms with all applicable fields filled in, applicable fees, and additional information needed by the Executive Officer to make a determination. PR 1109.1 includes the phrase "complete permit application" to ensure the Facilities submit all required information in order for the South Coast AQMD to meet the tight timelines and issue the plans and permits in a timely manner.

Compliance Schedule for Boilers and Process Heaters Less Than 40 MMBtu/hour – Paragraph (f)(2)

The NOx limit of 40 ppmv for Boilers and Process Heaters less than 40 MMBtu/hour is lowered to 5 ppmv for Boilers and 9 ppmv for Process Heaters when the owner or operator either cumulatively replaces 50 percent or more of the burners or the burners replaced cumulatively represent 50 percent or more of the Heat Input. The cumulative burner replacement provisions apply from a specified date to prevent a facility from replacing burners incrementally over time in order not to trigger a retrofit. The compliance schedule to achieve the two-step NOx Concentration Limits are provided in Table 4 of PR 1109.1, provided as Table 3-6 below. Additionally, owners or operators are required to maintain records for burner replacement for these boilers and process heaters to track burner replacement.

Boilers Less than 40 MMBtu/Hour

The first NOx Concentration Limit for Boilers less than 40 MMBtu/hour, pursuant to subparagraph (d)(2)(A), is 40 ppmv. Complete permit applications must be submitted by July 1, 2022, and the compliance date begins when South Coast AQMD issues the Permit to Operate as all of these units are currently achieving less than 40 ppmv NOx.

The second NOx Concentration Limit is 5 ppmv pursuant to subparagraph (d)(2)(B). The complete permit applications are due based on burner replacement and is due no later than six months from the either when 50 percent or more of the burners are cumulatively replaced or the burners replaced cumulatively represent 50 percent or more of the Heat Input, with the cumulative replacement of burners beginning to be effective from July 1, 2022. The Boiler will be required to meet the 5 ppmv NOx limit 18 months from the date the Permit to Construct is issued by South Coast AQMD.

Process Less than 40 MMBtu/Hour

The first NOx Concentration Limit for these Process Heaters less than 40 MMBtu/hour, pursuant to subparagraph (d)(2)(A), is 40 ppmv and complete permit applications must be submitted by July 1, 2023. The compliance date begins when South Coast AQMD issues the Permit to Operate or 18 months from the date the Permit to Construct is issued by South Coast AQMD, whichever is sooner. Additionally, Facilities have the option to immediately meet the second step NOx concentration limit of 9 ppmv. For these Facilities, the compliance date will be 36 months from the date the Permit to Construct is issued by South Coast AQMD. PR 1109.1 includes a longer compliance schedule to implement the lower NOx limit to incentivize early adoption of the emerging technologies.

The second NOx Concentration Limit is 9 ppmv pursuant to subparagraph (d)(2)(C). Since the emission reduction technologies for Process Heaters are based on emerging technologies, the NOx limit of 9 ppmv is effective ten years after rule adoption to provide time for the emerging technologies to further develop. The complete permit applications are due based on burner replacement, no later than six months from the either when 50 percent or more of the burners are cumulatively replaced or the burners replaced cumulatively represent 50 percent or more of the Heat Input, with the cumulative replacement of burners beginning to be effective beginning five year after rule adoption with the compliance date will be 18 months from the date the Permit to Construct is issued by South Coast AQMD. Most, but not all, Process Heaters less than 40 MMBtu/hour are currently achieving the first 40 ppmv NOx limit; however, several Units will have to be retrofit. The five-year time allowance to begin counting the cumulative burner replacement is to address the time needed to retrofit those units to meet the 40 ppmv NOx limit.

Staff believes that implementation of the B-Plan and B-Cap will help incentivize owners or operators to accelerate introduction and commercialization of emerging technologies. Staff will monitor the development of the emerging technologies and will include in the Resolution a commitment to report on the status of the emerging technologies in 2029 and conduct a technology assessment if these technologies are not being commercialized.

Table 3-5. PR 1109.1 Table 4 – Compliance Schedule for Boilers and Process Heaters Less Than 40 MMBtu/Hour

<table>
<tr><th>Unit</th><th>NOx Concentration Limit (ppmv)</th><th>Permit Application Submittal Date</th><th>Compliance Date</th></tr>
<tr><td rowspan="2">Boilers <40 MMBtu/ hour</td><td>40 ppmv pursuant to subparagraph (d)(2)(A)</td><td>On or before July 1, 2022</td><td>• On and after the date the South Coast AQMD issues a Permit to Operate</td></tr>
<tr><td>5 ppmv pursuant to subparagraph (d)(2)(B)</td><td>Pursuant to subparagraph (f)(2)(B)</td><td>• On and after 18 months from the date the South Coast AQMD issues a Permit to Construct</td></tr>
<tr><td rowspan="2">Process Heaters <40 MMBtu/ hour</td><td>40 ppmv pursuant to subparagraph (d)(2)(A)</td><td>On or before July 1, 2023</td><td>• On and after the date the South Coast AQMD issues the Permit to Operate or on and after 18 months from the date the South Coast AQMD issues a Permit to Construct, whichever is sooner; or
• On and after 36 months from the date the South Coast AQMD issues a Permit to Construct if the owner or operator of a Facility elects to meet the NOx concentration limit pursuant to subparagraph (d)(2)(C) in lieu of subparagraph (d)(2)(A)</td></tr>
<tr><td>9 ppmv pursuant to subparagraph (d)(2)(C)</td><td>Pursuant to subparagraph (f)(2)(C)</td><td>• On and after 18 months from the date the South Coast AQMD issues a Permit to Construct</td></tr>
</table>

Compliance Schedule for Table 2 Conditional Limit – Paragraph (f)(3)

PR 1109.1 allows an owner or operator that meets the conditions specified in paragraph (d)(3) to elect to meet Conditional NOx and Corresponding CO Concentration Limits in Table 2 in lieu of Table 1 Limits. If Facilities use this option, they must submit a complete permit application on or before June 1, 2022 to establish a condition to limit the NOx and CO emissions to a level not to exceed the applicable Table 2 Conditional NOx and Corresponding CO Concentration Limits and meet that limit no later than the date the Permit to Operate is issued or 18 months from the date the Permit to Construct is issued, whichever is sooner. Staff is proposing 18 months to meet the NOx concentration limit since the conditional limits were intended for those Units that are currently achieving NOx levels that are near the Table 2 limits and little to no physical modifications to the Unit are needed. Staff is proposing June 1, 2022 to provide lead time prior to the submittal of an I-Plan, B-Plan, and B-Cap. A commitment that an owner or operator will be meeting the conditional NOx limit is needed to allow an owner or operator to account for a Unit that is seeking compliance with Table 2 in lieu of Table 1 NOx limits when calculating the Facility BARCT Emission Target. Implementation of the conditional limits by requiring a permit application by July 1, 2022 will help to expedite BARCT implementation consistent with AB 617.

Modifications to Existing Units that are Meeting Table 2 Conditional NOx Concentration Limits – Paragraph (f)(4)

Paragraph (f)(4) includes provisions for owners or operators that significantly modify existing pollution controls on a Unit that were previously meeting the Table 2 Conditional NOx and Corresponding CO Concentration Limits. Under subparagraph (f)(4)(A), an owner or operator meeting the Table 2 Conditional NOx and Corresponding CO Concentration Limits will be required to submit a complete permit application prior to replacing the exiting NOx control equipment to accept the NOx Concentration Limit and Corresponding CO Concentration Limit in Table 1 if replacing: (1) an existing with a new post-combustion air pollution control equipment; (2) components of existing post-combustion air pollution control equipment; and (3) burners for Vapor Incinerators.

Clauses (f)(4)(A)(i) and (f)(4)(A)(ii), include provisions for replacement of existing post-combustion controls or the replacement of components of post-combustion controls applies to FCCUs, Gas Turbines fueled with Natural Gas, Process Heaters with a Heat Input Capacity at or greater than 40 MMBtu/hour, and SMR Heaters. Additionally, the provision for replacing components, clause (f)(4)(A)(ii), applies if the cost of the components being replaced is greater than 50 percent of the fixed capital cost that would be required to construct and install new post-combustion air pollution control equipment. Clause (f)(4)(A)(ii), applies to burner replacement for vapor incinerators, where replacement is based on if 50 percent or more of the burners are cumulatively replaced or the burners replaced cumulatively represent 50 percent or more of the Heat Input Capacity, where the cumulative replacement begins on rule adoption. This provision is to ensure if an owner or operator is making a significant modification to the listed equipment, the owner or operator will then be required to meet the Table 1 NOx and Corresponding CO Concentration Limits. Under subparagraph (f)(4)(B), the owner or operator must meet the Table 1 NOx Concentration Limit and Corresponding CO Concentration Limit no later than the date the Permit to Operate is issued or 18 months from the date the Permit to Construct is issued, whichever is sooner.

Exempted Units – Paragraph (f)(5)

Paragraph (f)(5) requires owners or operators with Units that are exempt pursuant to PR 1109.1 paragraphs (o)(2), (o)(3), (o)(5), (o)(6), (o)(8) and (o)(9) to submit a complete permit application by July 1, 2022 to meet the applicable limits required by the exemption. The applicable limits for the exemptions are as follows:

- Paragraphs (o)(2) and (o)(5), hours of operation per calendar year;
- Paragraph (o)(3), Rated Heat Input Capacity per calendar year;
- Paragraph (o)(6), Heat Input per calendar year; and
- Paragraphs (o)(8) and (o)(9), pounds of NOx per calendar year.

Exempted Units Exceeding Limits – Paragraph (f)(6)

Certain Units are exempt from the NOx and Corresponding CO Concentration Limits in Table 1, but have different applicable limits (e.g., hours of operation per calendar year or pounds of NOx per calendar year). Paragraph (f)(6) includes provisions for an owner or operator that exceeds the limits in required by the exemption. A complete permit application to meet the applicable NOx and Corresponding CO Concentration Limit in Table 1 must be submitted within six months of the exceedance. The deadline to comply with the Table 1 limits is no later than the date the Permit to Operate is issued or 18 months from the date the Permit to Construct is issued, whichever is sooner. Any unit that was exempt, and exceeds a limit is no longer exempt, cannot be included in B-Plan, B-Cap, or I-Plan and must comply with Table 1 limits.

Failure to Submit a Permit Application – Paragraph (f)(7)
Paragraph (f)(7) includes provisions for an owner or operator that fails to submit a permit application on time. This provision is to ensure that if an owner or operator submits a permit application late, the owner or operator will not be afforded additional time to meet the NOx and Corresponding CO limit. Under this provision, if an owner or operator fails to submit a permit application by the deadline in PR 1109.1, the owner or operator shall meet the applicable NOx Concentration Limit either 36 or 24 months from when the permit application is submitted, as compared to when the permit to construct is issued for most provisions under PR 1109.1. This provision is designed to strongly discourage late submittals of permit applications.

Provisional Averaging Time – Paragraph (f)(8)
During the rulemaking process some owners or operators commented that achieving the shorter averaging times and lower NOx Concentration Limits in PR 1109.1 will be challenging as owners or operators are currently accustomed to an annual compliance cycle under the RECLAIM program. Achieving the PR 1109.1 NOx Concentration Limits in Table 1 and Table 2 will require shorter compliance periods for all Units other than the FCCUs, Petroleum Coke Calciners, and Sulfuric Acid Plants, which will be subject to 365-day rolling averages. To address this additional challenge, for Units with an approved CEMS and subject to a rolling average less than 365 days, compliance with the NOx Concentration Limits or Alternative BARCT NOx Limits, and Corresponding CO Concentration limits must be demonstrated six months after the issuance of the Permit to Operate, 36 months after the Permit to Construct is issued, or immediately after completion of a compliance demonstration source test, whichever is soonest. This consideration allows for applying any necessary adjustments to ensure NOx emission levels can be met within the required averaging times.

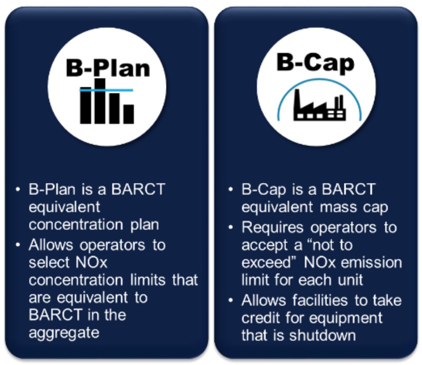
Initial Averaging Time for Units with a 365-Day Averaging Time Period – Paragraph (f)(9)
An owner or operator of a Unit subject to a 365-day rolling average shall demonstrate compliance with the applicable NOx Concentration Limit or Alternative BARCT NOx Limit beginning 14 months after the South Coast AQMD Permit to Operate is issued, 36 months after the Permit to Construct is issued, or immediately after completion of a compliance demonstration source test, whichever is soonest. This consideration allows for applying any necessary adjustments to ensure NOx emission levels can be met within the required averaging times.

Decommissioned Units – Paragraph (f)(10)
Units that will be decommissioned to comply with this rule will need to: 1.) surrender the Unit’s Permit to Operate; 2.) disconnect and blind the Unit’s fuel lines; and 3.) not sell the Unit for operation within the South Coast Air Basin.
The compliance schedule for decommissioned Units is dependent on which plan the Facility elects.

- If the Unit is excluded from a B-Plan, then the owner or operator shall comply within 54 months from the Phase I Permit Application Submittal Date specified in Table 6 for the I-Plan option selected.
- If an approved B-Plan is modified to remove a Unit that will be decommissioned, then the owner shall comply by the date specified by the Executive Officer.

- If a New Unit is replacing an entire or part of a decommissioned Unit to meet the requirements of an approved B-Cap and an approved I-Plan, then owner or operator shall comply within 90 days from commissioning a New Unit.
- If a Unit is to be decommissioned and not being replaced with a New to meet the requirements of an approved B-Cap and an approved I-Plan, then owner or operator shall comply no later than the B-Cap Effective Date of the Facility BARCT Emission Target specified in Table 6 for the I-Plan option selected for a B-Cap.

SUBDIVISION (g) – B-PLAN AND B-CAP REQUIREMENTS



PR 1109.1 includes two alternative compliance options to directly meeting the NOx Concentration Limits in Table 1 or Table 2 for owners or operators with six or more Units. These alternative compliance options were developed to address the complexity of operations at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries, recognizing that achieving the Table 1 NOx Concentration Limits may be more challenging for some Units, as owners or operators are integrating new pollution control equipment on existing Units within the existing configuration of their Facility. The B-Plan is a BARCT Equivalent Compliance Plan and is designed to achieve the NOx and CO Concentration Limits in Table 1 and Table 2, in aggregate. The B-Cap is a BARCT Equivalent Mass Cap Plan and is designed to achieve the NOx Concentration Limits in Table 1 and Table 2, based on aggregate mass emissions. Both the B-Plan and B-Cap are designed to achieve similar NOx emission reductions as if owners or operators were directly complying with Table 1 and Table 2 NOx and CO Concentration Limits.

Paragraphs (g)(1) and (g)(2) establish the requirements for the B-Plan and B-Cap, respectively. Owners or operators that elect to use an alternative compliance option, must select either the B-Plan or the B-Cap and submit the plan on or before September 1, 2022. Both the B-Plan and the B-Cap require owners or operators to submit a permit application to limit the NOx concentration to the selected Alternative BARCT NOx Limit for each Unit. Implementation of projects to achieve the Alternative BARCT NOx Limit in the B-Plan and the B-Cap are based on the schedule in the approved I-Plan. At full implementation, all Units regulated under PR 1109.1 will have an enforceable NOx concentration permit limit.

> BARCT EQUIVALENT COMPLIANCE PLAN (B-PLAN) means a compliance plan that allows an owner or operator of a Facility to select Alternative BARCT NOx Limits for all Units subject to the B-Plan that will achieve emission reductions that are greater in the aggregate than the mass emission reductions that would be achieved based on the NOx Concentration Limits in Table 1 – NOx and CO Concentration Limits (Table 1) or Table 2 – Conditional NOx and CO Concentration Limits (Table 2).

Requirements for the B-Plan - Paragraph (g)(1)

Under the B-Plan, owners or operators select an Alternative BARCT NOx Limit for each Unit. If the owner or operator can meet the conditions of the Conditional NOx Concentration Limits under paragraph (d)(3), the Alternative BARCT NOx Limit cannot exceed the Table 2 NOx Concentration Limit, with the exception of any Unit identified in Table D-1 of PR 1109.1. Pursuant to paragraph (d)(3), a Unit listed on Table D-1 is not limited to the NOx concentration limits in Table 2 and the owner or operator can submit complete permit applications for these Units based on the established Alternative BARCT NOx Limits in the approved I-Plan.

An owner or operator that elects to meet the Table 1 and Table 2 NOx Concentration Limits and Corresponding CO Limits through implementation of a B-Plan is required to:

- Submit a B-Plan on or before September 1, 2022;
- Identify all Units subject to the Rule 1109.1 B-Plan
- Select an Alternative BARCT NOx Limit for each Unit and calculate the BARCT Equivalent Mass Emissions, with specific requirements for Units meeting the Conditional NOx Concentration Limits; and
- Not include any Unit that has been or will be decommissioned.

Units to be Included in the B-Plan – Subparagraph (g)(1)(B)
Under the B-Plan, all Units are to be included in the B-Plan with a few exceptions. Pursuant to subparagraph (g)(1)(B) Units that can be excluded include Optional Units, which are Boilers or Process Heaters with a Rated Heat Input Capacity of less than 40 MMBtu/hour that will meet the NOx concentration limits pursuant to subparagraph (d)(2)(B) or (d)(2)(C); Units that will be decommissioned 54 month from the permit submittal date of Phase I of the selected I-Plan, and some units that are exempt from the NOx Concentration Limits in Table 1 because they are low use under paragraphs (o)(2) (low-use boilers < 40 MMBtu/hr), (o)(5) (FCCU boilers or process heaters operating less than 200 hours per year), (o)(6) (startup or shutdown boilers and process heaters using less than 90,000 MMBtu annually), (o)(8) (flares that emit ≤ 550 of NOx per year, and (o)(9) (vapor incinerators emitting less than 100 pounds of NOx per year for unlimited exemption or less than 1,000 pound of NOx per year for limited exemption), and Units listed under paragraph (o)(1) (boilers or process heaters ≤ 2 MMBtu/hr used for comfort heating) shall not be included in the B-Plan. Any Unit that has been decommissioned should not be included in the B-Plan.

With regard to the B-Plan, in communication with U.S. EPA, the B-Plan will result in an environmental benefit by requiring BARCT Equivalent Mass Emissions, based on Alternative BARCT limits, to be less than (not equal to) the Facility BARCT Emission Target, which is derived from applicable BARCT NOx limits in Table 1 and Table 2. In addition, the B-Plan does not allow shutdowns and the Alternative BARCT NOx limits used in the B-Plan are either at or below RACT.

Calculating the BARCT Equivalent Mass Emissions -Subparagraph (g)(1)(C)
The methodology for calculating the BARCT Equivalent Mass Emissions is presented in Attachment B. Subparagraph (g)(1)(C) specifies parameters for the NOx concentration values that must be used in this calculation. The operator is responsible for selecting the Alternative BARCT NOx Limit and identifying which phase that the Alternative BARCT NOx Limit will be implemented. For an I-Plan, for any Unit that meets the conditions for Table 2 NOx Concentrations because the operator has submitted a permit application by June 1, 2022, must limit the Alternative BARCT NOx Limit to Table 2 NOx Concentrations. This provision clarifies that any Unit where the Alternative NOx BARCT Limit has not yet been identified for a phase of the I-Plan, that the Representative NOx Concentration which would be representative of the Baseline NOx Emissions will be used to calculate the BARCT Equivalent Mass Emissions and is for the purpose calculating

the BARCT Equivalent Mass Emissions. This section also requires that the operator demonstrate that by the final phase of the I-Plan, each Unit will be assigned an Alternative BARCT NOx Limit.

Implementation of an Approved B-Plan – Paragraph (g)(2)

Paragraph (g)(2) establishes the requirements after approval of an I-Plan and B-Plan pursuant to paragraph (i)(4). After an owner or operator receives approval of an I-Plan and B-Plan, the operator is required to submit a complete Permit application to apply for a condition that limits the NOx limits not to exceed the Alternative BARCT NOx Limit and Corresponding CO Limits based on the schedule in the approved I-Plan. An operator must not operate a Unit unless the NOx and CO concentration levels are below the Alternative BARCT NOx Limits. By the final implementation phase in the I-Plan, an Alternative BARCT NOx Limit must be identified for each Unit in the I-Plan, where the permit application submittal is based on the dates in approved I-Plan. An Alternative BARCT NOx Limit is required for all Units in the I-Plan, regardless of if the Unit is modified to add pollution controls. This ensures that each Unit has an enforceable NOx concentration limit for each Unit in the I-Plan.

Requirements for the B-Cap - Paragraph (g)(3)

B-CAP means a compliance plan that establishes a Facility mass emission cap for all units subject to the B-Cap that, in the aggregate, is less than the Final Phase Facility BARCT Emission Target.

Under the B-Cap, the requirements are the same as for an operator that elects to use a B-Plan for the provisions listed above, with the exception of provisions for using Table 2 Conditional Limits. Since decommissioned Units are allowed under the B-Cap the provision to remove a Unit that will be decommissioned within Phase I is not included in the B-Cap. In addition, there are additional provisions for the B-Cap to provide safeguards to ensure the B-Cap remains equivalent to Table 1 and Table 2 NOx Concentration Limits based on aggregate mass emissions. These additional provisions are discussed below.

Calculating the BARCT Equivalent Mass Emissions - Subparagraph (g)(3)(C)

The methodology for calculating the BARCT Equivalent Mass Emissions is presented in Attachment B. Subparagraph (g)(3)(C) specifies parameters for the NOx concentration values that must be used in this calculation. The provisions are identical to the B-Plan, with one additional criteria that while the Representative NOx Concentration may exceed Maximum Alternative BARCT NOx Concentration Limits in Table 5, however, the Alternative NOx BARCT Limit cannot exceed the Maximum Alternative BARCT NOx Concentration Limits for a B-Cap pursuant to Table 5 of PR 1109.1. Similar to the discussion for the B-Plan, the use of the Representative NOx Concentration is for calculating the BARCT Equivalent Mass Emissions.

Table 3-6. PR1109.1 Table 5 – Maximum Alternative BARCT NOx Concentration Limits for a B-CAP

Unit	Maximum Alternative BARCT NOx Limit	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers and Process Heaters <40 MMBtu/hour	40 ppmv	3	24-hour
Boilers and Process Heaters ≥40 MMBtu/hour	50 ppmv	3	24-hour
FCCUs	8 ppmv	3	365-day
	16 ppm		7-day
Gas Turbines	5 ppmv	15	24-hour
Petroleum Coke Calciners	100 tons/year	N/A	365-day
SMR Heaters	12 ppm	3	24-hour
SRU/TG Incinerators	100 ppmv	3	24-hour
Vapor Incinerators	40 ppmv	3	24-hour

[1] Averaging times apply to Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule; compliance for Units without a certified CEMS shall be demonstrated pursuant to paragraph (l)(1).

Calculating the BARCT B-Cap Annual Emissions – Subparagraph (g)(3)(D)

Under the B-Cap, operators have three mechanisms to reduce mass emissions: (1) Lower the NOx concentration level of the Unit; (2) decommissioning units, and (3) implement other emission reduction strategies such as reduced throughput, capacity, or any other emission reduction strategy that would lower mass emissions. Under the B-Cap, operators can use any of the three emission reduction strategies to reduce mass emissions from Units in the B-Plan but must also demonstrate daily that actual emissions are below the Facility BARCT Emission Target based a rolling 365-day average. In addition, the Facility BARCT Emission Target is based on Table 1 and Table 2 NOx Concentration Limits, plus an additional 10 percent reduction to benefit the environment. This is a 10 percent reduction in NOx, that operators that use a B-Cap are required to achieve. The 10 percent environmental benefit is included to meet U.S. EPA guidelines for economic incentive programs. U.S. EPA views the B-Cap as an economic incentive program as it allows trading of emission reductions within a facility emissions cap and allows the use of reductions from decommissioned Units to meet emission reduction obligations. For a more detailed discussion of the 10 percent environmental benefit, refer to the section on Subdivision (h) of PR 1109.1 in this Staff Report.

> BARCT B-CAP ANNUAL EMISSIONS means the sum of the mass emissions from the Unit B-Cap Annual Emissions for each phase of an I-Plan, that is based on the Alternative BARCT NOx Limits, decommissioned Units, and other emission reduction strategies to meet the Facility BARCT Emission Targets in an I-Plan as calculated pursuant to Attachment B of this rule.

Implementation of a B-Cap – Paragraph (g)(4)

Paragraph (g)(4) establishes the requirements after approval of an I-Plan and B-Cap pursuant to paragraph (i)(4). After an owner or operator receives approval of an I-Plan and B-Plan, the operator is required to submit a complete Permit application to apply for a condition that limits the NOx limits not to exceed the Alternative BARCT NOx Limit and Corresponding CO Limits based on the schedule in the approved I-Plan.

Not Operate a Unit above the Alternative BARCT NOx Limit – Subparagraph (g)(4)(B)
Subparagraph (g)(4)(B) specifies that a Unit cannot exceed the Alternative BARCT NOx Limit based on the schedule in the approved I-Plan. By the final implementation phase in the I-Plan, an Alternative BARCT NOx Limit must be identified for each Unit in the I-Plan, where the permit application submittal is based on the dates in approved I-Plan. An Alternative BARCT NOx Limit is required for all Units in the I-Plan, regardless of if the Unit is modified to add pollution controls. This ensures that each Unit has an enforceable NOx concentration limit for each Unit in the I-Plan.

For Units that are included in a B-Cap, the startup and shutdown emissions may be excluded from demonstrating compliance with the NOx concentration limits (e.g., the Alternative BARCT NOx Limits) in accordance with the provisions in Rule 429.1; however, startup and shutdown emissions must be included when demonstrating the facility's daily mass emissions are below the mass cap based on the 365-day rolling average.

Decommissioned Units Under the B-Cap – Subparagraph (g)(4)(C)
Under the B-Cap, an operator can permanently decommission a Unit to meet the Facility BARCT Target since emissions from all units are "capped" and the facility is meeting BARCT based on mass emissions. The owner or operator of a Unit that elects to decommission a Unit under a B-Cap is required to reflect the emissions from the decommissioned unit as Table 1 emissions in the Final Phase Facility BARCT Emission Target. For any Unit that is decommissioned, the South Coast AQMD Permit to Operate must be surrendered, and the owner shall disconnect and blind the fuel line(s) to the unit and not sell the unit for operation to another entity within the South Coast Air Basin. Provisions for decommissioning a Unit and the schedule to decommission a Unit are discussed under paragraph (f)(10).

Daily Demonstration that Units in the B-Cap are Below the Facility BARCT Emission Target – Subparagraph (g)(4)(D)
It is expected that operators that are using a B-Cap will have higher Alternative BARCT NOx Concentration Limits for each individual Unit compared to Units under the B-Plan. However, the B-Cap has two additional safeguards to address this issue. The first provision limits the Alternative BARCT NOx Concentration Limits to ensure that each Unit has pollution controls (subparagraph (g)(4)(B)). Under PAR 1109.1, the Alternative BARCT NOx Limits cannot exceed the Maximum Alternative NOx Concentration Limits in Table 5 of PR 1109.1. The second provision is the mass emissions cap, and the daily demonstration that operators are below the Facility BARCT Emission Target based on a rolling 365-day average (subparagraph (g)(4)(D)). This ensures that although some Units will individually have higher Alternative BARCT NOx Concentration Limits the operation of these, and all Units cannot exceed the mass emissions cap. Although Alternative NOx Concentrations may be higher than those under a B-Plan and the B-Cap some additional flexibilities such as the use of decommissioned Units and other emission reduction strategies, this second compliance component ensures that mass emissions, based on an annual average, are representative of the Units meeting Table 1 and Table 2 NOx Concentration Limits. It should also be noted, that under the B-Plan mass emissions are not capped, while emissions under the B-Plan are.

Provisions for New Units – Subparagraph (g)(4)(E)

PR 1109.1 has additional provisions for operators with a B-Cap for New Units. PR 1109.1 requires that the operator demonstrates that one or more of the following criteria are met before a New Unit is added to the Facility. The operator is also required to provide in writing at the time the permit application is submitted for the New Unit, which of the conditions have been met.

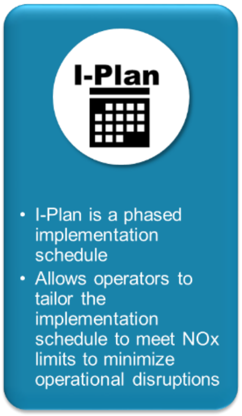
- The unit for which permit application is being submitted is not subject to this rule or is a Unit that will meet an exemption pursuant to paragraphs (o)(1), (o)(2), (o)(3), (o)(5), (o)(6), (o)(8), or (o)(9), if the operator met this condition the New Unit would not need to be added to the B-Cap. The New Unit must meet all of the requirements including any permit condition for limiting hours of operation or fuel usage that is specified in subdivision o for those exemptions.
- The BARCT Equivalent Mass Emissions with the New Unit is below the Facility BARCT Emission Target for the current and any future phase of the I-Plan, as calculated in Attachment B, if the operator met this condition the New Unit would not need to be added to the B-Cap. This provision is the same criteria used for a B-Plan and ensures that all Units that were not decommissioned meet the NOx Concentration Limits in Table 1 and Table 2 in aggregate, where no emissions budget from a Unit that was decommissioned can be used to establish a higher Alternative NOx Concentration Limit.
- The New Unit is not Functionally Similar to any Unit that was decommissioned in the approved B-Cap and the New Unit will not increase the overall facility throughput, if the operator met this condition the New Unit would not need to be added to the B-Cap;
- The total amount of NOx emission reductions from units that were decommissioned, represents 15 percent or less of the Final Phase Facility BARCT Emission Target in an approved B-Cap and the B-Cap is modified to include the New Unit and the Facility BARCT Emission Target is adjusted to incorporate the New Unit;
- The New Unit is Functionally Similar to any Unit that was decommissioned, and the B-Cap is modified with no increase of the Facility BARCT Emission Target. Any Unit that was decommissioned had an emissions budget in the B-Cap that was based on the Table 1 NOx Concentration Limit. Staff believes any New Unit that is Functionally Similar, which includes Units that are different equipment categories but provide the same purpose, should not be allowed to have an additional emissions budget in the Facility BARCT Emission Target.

The provisions for new units and unit decommissioning are to prevent a facility from shutting down units instead of installing controls on units. While shutting down a unit will result in emission reductions, the intent of PR 1109.1 is to require facilities to have BARCT levels of control on all units, or BARCT equivalent emissions in the aggregate. If a facility were to decommission a unit, take credit for the emission reductions in the B-CAP, and later install a functionally similar unit outside the B-Cap, the B-Cap would no longer be BARCT equivalent. It would not be equitable that the emissions budget from decommissioning a unit was used to allow another unit to not install pollution controls, and later install a unit that is functionally similar to the unit that was decommissioned.

SUBDIVISION (h) - I-PLAN REQUIREMENTS

An I-Plan is compliance plan that provides an alternative implementation schedule to the compliance schedule in paragraph (f)(1) which would require that all permits be submitted by January 1, 2023. An I-Plan is required for facilities that elect to comply with either a B-Plan or a

B-Cap or a facility that elects to have an alternative compliance schedule for meeting Table 1 or Table 2 NOx Concentration Limits and Corresponding CO Concentration Limits.



General Requirements of an I-Plan – Paragraph (h)(1)

An owner or operator that elects to implement an I-Plan, must submit an I-Plan pursuant to paragraph (i)(1). Similar to the B-Plan and B-Cap, the I-Plan is only for Facilities with six or more Units. The I-Plan must include all of the Units included in the accompanying B-Plan if the Facility is electing to comply with a B-Plan and all of the Units included in the accompanying B-Cap if the facility is electing to comply the B-Cap. Operators do have the option to comply with the Table 1 or Table 2 limits using an alternative schedule in an I-Plan, for those operators the I-Plan must include all units at the Facility subject to the rule with the option to exclude "Optional Units" and Units that are complying with the rule under one of the exemption in under paragraphs (o)(2), (o)(5), (o)(6), (o)(8), and (o)(9). Units listed in paragraph (o)(1) shall not be included in the I-Plan as those units are subject to 1146.1 and will not be subject PR 1109.1.

The Units included in the I-Plan must be located at either a single Facility or Facilities Identify all Facilities With The Same Ownership and the owner or operator must identify the Facilities, identified by the facility identification numbers, in the I-Plan.

Selecting an I-Plan Option – Paragraph (h)(2)

The I-Plan allows refineries to implement projects within their turnaround schedules to minimize operational disruptions. Staff consulted with refineries to develop the five I-Plan options and timeframes and percent reductions. Each of the five I-Plan options have specific use criteria, such as implementation of a B-Plan, a B-Cap, or meeting Table 1 and Table 2 NOx Concentration Limits. I-Plan Option 2 and Option 3 is only available to the owner or operator of a facility that is achieving a NOx emission rate of less than 0.02 pound per million BTU of heat input for all the Boilers and Process Heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour or any Boiler or Process Heater with a rated heat input capacity of less than 40 MMBtu/hours that operates with a certified CEMS, based on the Maximum Rated Heat Input Capacity. The facility would be required to perform a one-time demonstration that their applicable boilers and process heaters meet the 0.02 pound per million BTU emission rate based on the 2021 annual emissions for those units as reported in the 2021 Annual Emissions Report.

OPTIONAL UNITS are Boilers or Process Heaters less than 40 MMBtu/hour that will meet the NOx concentration limits pursuant to subparagraph (d)(2)(B) or (d)(2)(C).

Table 6 lists the key elements of the each of the I-Plan options. The emission reductions are phased-in in either two or three. The "Percent Reduction Targets" are the percent reduction for each phase of the selected I-Plan that are applied to the total reductions required for each Facility. The "Permit Application Submittal Date" is the date that permits must be submitted to establish an Alternative BARCT NOx Limit. The "Compliance Schedule" is the timeframe the facility has to meet the Alternative BARCT NOx Limit for each Phase. By the last phase of the I-Plan, all units must have a permit condition that limits the units to the Alternative BARCT NOx limit for a facility complying with either a B-Plan or a B-Cap, or the Table 1 or Table 2 NOx concentration limits.

For a B-Cap, Table 6 specifies the "B-Cap Effective Date of the Facility BARCT Emission Target" which represents the first day of the 365 days that will be used to calculate the 365-day rolling average. The compliance demonstration for the 365-day rolling average begins 365 days after the B-Cap Effective Date.

Table 3-7. PR 1109.1 Table 6 – I-Plan Percent Reduction Targets of Required Reductions and Compliance Schedule

<table>
<tr><th>I-Plan Option</th><th>Key Elements</th><th>Phase I</th><th>Phase II</th><th>Phase III</th></tr>
<tr><td rowspan="3">I-Plan Option 1 for B-Plan or Concentration Limits in Table 1 or Table 2</td><td>Percent Reduction Targets</td><td>80</td><td>100</td><td>N/A</td></tr>
<tr><td>Permit Application Submittal Date</td><td>January 1, 2023</td><td>January 1, 2031</td><td>N/A</td></tr>
<tr><td>Compliance Schedule</td><td colspan="2">No later than 36 months after a Permit to Construct is issued</td><td>N/A</td></tr>
<tr><td rowspan="3">I-Plan Option 2 for B-Plan Only pursuant to subparagraph (h)(2)(E)</td><td>Percent Reduction Targets</td><td>65</td><td>100</td><td>N/A</td></tr>
<tr><td>Permit Application Submittal Date</td><td>July 1, 2024</td><td>January 1, 2030</td><td>N/A</td></tr>
<tr><td>Compliance Schedule</td><td colspan="2">No later than 36 months after a Permit to Construct is issued</td><td>N/A</td></tr>
<tr><td rowspan="4">I-Plan Option 3 for B-Plan or B-Cap pursuant to subparagraph (h)(2)(E)</td><td>Percent Reduction Targets</td><td>40</td><td>100</td><td>N/A</td></tr>
<tr><td>Permit Application Submittal Date</td><td>July 1, 2025</td><td>July 1, 2029</td><td>N/A</td></tr>
<tr><td>Compliance Schedule</td><td colspan="2">No later than 36 months after a Permit to Construct is issued</td><td>N/A</td></tr>
<tr><td>B-Cap Effective Date of the Facility BARCT Emission Target</td><td>January 1, 2030</td><td>January 1, 2034</td><td>N/A</td></tr>
<tr><td rowspan="4">I-Plan Option 4 for B-Cap Only</td><td>Percent Reduction Targets</td><td>50</td><td>80</td><td>100</td></tr>
<tr><td>Permit Application Submittal Date</td><td>N/A</td><td>January 1, 2025</td><td>January 1, 2028</td></tr>
<tr><td>Compliance Schedule</td><td>January 1, 2024</td><td colspan="2">No later than 36 months after a Permit to Construct is issued</td></tr>
<tr><td>B-Cap Effective Date of the Facility BARCT Emission Target</td><td>January 1, 2024</td><td>July 1, 2029</td><td>July 1, 2032</td></tr>
</table>

I-Plan Option	Key Elements	Phase I	Phase II	Phase III
I-Plan Option 5 for B-Plan Only or Concentration Limits in Table 1 or Table 2	**Percent Reduction Targets**	**50**	**70**	**100**
	Permit Application Submittal Date	January 1, 2023	January 1, 2025	July 1, 2028
	Compliance Schedule	No later than 36 months after a Permit to Construct is issued		

The I-Plan schedule in Table 6 includes a 36-month compliance timeline to complete all of the NOx reduction projects included in each phase. Staff does not view the implementation period provided in Table 6 to be in conflict with Rule 205 that states "A permit to construct shall expire one year from the date of issuance unless an extension of time has been approved in writing by the Executive Officer." This rule and its general provisions will have the approval of the Executive Officer unless the rule requires an additional Executive Officer approval (e.g., an I-Plan, B-Plan, B-Cap, etc.).

Baseline NOx Emissions and Representative NOx Concentrations – Paragraph (h)(3)

Baseline NOx Emissions and Representative NOx Concentrations are used to calculate Final Phase Facility BARCT Emission Target, the Facility BARCT Emission Targets, and BARCT Equivalent Mass Emissions for each phase of the I-Plan. During the rulemaking process staff has been working with operators to ensure that the Baseline NOx Emissions and Representative NOx Concentrations for each Facility are accurate. Since this emissions data is important to approving any I-Plan, PR 1109.1 establishes a process for final revisions, and then the data will be formalized for use for the I-Plans and implementation of B-Plans and B-Caps.

A separate document titled "Baseline NOx Emissions and Representative NOx Concentrations for Facilities Regulated Under Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations" will be presented to the South Coast AQMD Board for approval at the adoption Public Hearing for PR 1109.1. Pursuant to paragraph (f)(3), the Baseline NOx Emissions and Representative NOx Concentrations for each facility by Unit (listed by Unit ID) approved by the South Coast AQMD shall be used, unless the owners or operators request in writing a change, the Executive Officer approves the change, and if the changes are greater than five percent, the change is presented to the Stationary Source Committee no later than February 18, 2022. After any changes are presented to the Stationary Source Committee, operators cannot change the Baseline NOx Emissions or Representative NOx Concentrations for any Unit, and must use the approved values for all emissions calculations for the I-Plan, B-Plan, and B-Cap. This approach provides greater transparency and is expected to help reduce possible delays with approving I-Plans, B-Plans, and B-Caps.

FACILITY BARCT EMISSION TARGET means the total remaining NOx emissions that are based on the Percent Reduction Targets in each phase of a Table 6 I-Plan that are applied to the overall NOx emission reductions for the Units included in an approved B-Plan or B-Cap, as calculated pursuant to Attachment B of this rule.

NOx Concentration Limits for Final Phase Facility BARCT Emission Target – Paragraph (h)(4)

Paragraph (h)(4) specifies the NOx Concentration Limits that must be used to calculate the Final Phase Facility BARCT Emission Target. Operators must use Table 1 NOx Concentration Limits for any Unit that is not listed Table 3-8. PR 1109.1 also requires that for a Unit that is designated to be decommissioned under a B-Cap, for the NOx Concentration Limit in Table 1 must be used when calculating the Final Phase Facility BARCT Emission Target.

For the conditional NOx limits, there are two pathways that an operator can take to qualify to use the Conditional Limits in Table 2 to calculate the Final Phase Facility BARCT Emissions Target for a Unit. Both pathways are designed to achieve earlier NOx reductions to be consistent with the intent of AB 617.

- ✓ The first pathway is that the operator demonstrates that the Unit will meet the conditions to use the conditional NOx Concentration Limits pursuant to paragraph (d)(3) and submits a permit application on or before June 1, 2022 for a permit condition to limit the NOx to a level not to exceed the applicable conditional NOx Concentration Limit and Corresponding CO Concentration Limits in Table 2 pursuant to subparagraph (f)(3)(A).
- ✓ The second pathway is for Units that are identified in Attachment D of PR 1109.1. Any Unit listed in Attachment D, is "pre-qualified" and operators would submit a permit application during one of the phases of the I-Plan to establish the Alternative NOx Limit, which is not limited to the levels specified in Table 2. Table D-1 applies to facilities with a B-Plan or a B-Cap using I-Plan Option 3 and includes those Boilers and Process Heater with a Rated Heat Input Capacity greater than or equal to 40 MMBtu/hour that were removed from the cost-effectiveness analysis for Table 1 due to either low emission reduction potential or high capital costs. Table D-2 applies only to facilities with a B-Cap that have selected I-Plan Option 4 and includes units that the South Coast AQMD staff has determined to meet all of the conditions in subparagraph (d)(3)(A) and Boilers and Process Heater with a Rated Heat Input Capacity greater than or equal to 40 MMBtu/hour that have a representative NOx concentration level at or below 25 ppmv. Table D-2 also includes Units that met the conditions under paragraph (d)(3) for Units other than Boilers and Process Heaters greater than or equal to 40 MMBtu/hour. Units listed under Table D-2 were added since an operator that is implementing I-Plan Option 4 will achieve 50 percent of their targeted emission reductions by January 1, 2024 and will be limited to using only the Units listed in Table D-2 ~~as~~ at Table 2 limits when establishing the Final Phase Facility BARCT Emissions Target.

Table 3-8. NOx Concentration Limits for Final Phase Facility BARCT Target

NOx Concentration Limit		Unit or Specific Provision for Unit
Table 1 NOx Concentration Limits		Any Unit not listed below and Unit that will be decommissioned under a B-Cap
Table 2 Conditional NOx Limit	An operator that does not select I-Plan Option 4	Meets the conditions in paragraph (d)(3) and permit application was submitted pursuant to subparagraph (f)(3)(A)
		Is listed in Table D-1 in Attachment D of this rule, for an owner or operator submitting a B-Plan or a B-Cap

	An operator submitting a B-Cap that selects I-Plan Option 4	Is listed in Table D-2 in Attachment D of this rule, for an owner or operator submitting a B-Cap that selects I-Plan Option 4
5 ppmv		Boiler with a Rated Heat Input Capacity less than 40 MMBtu/hour
40 ppmv		Process Heater with a Rated Heat Input Capacity less than 40 MMBtu/hour with a representative NOx Concentration ≥ 75 ppmv provided operator achieves NOx Concentration within Phase I of an I-Plan and any additional reductions to meet the final NOx Concentration Limit are not used to meet Facility BARCT Target
9 ppmv		Process Heaters with a Rated Heat Input Capacity of less than 40 MMBtu/hour with a Representative NOx Concentration less than 75 ppmv

Operators have the option to exclude Boilers and Process Heaters less than 40 MMBtu/hour from the I-Plan, B-Plan, and B-Cap. However, if an operator includes a Boiler or Process Heater less than 40 MMBtu/hour in the I-Plan, for most situations the NOx Concentration Limit for the Final Phase BARCT Emission Target will be the final NOx Concentration limit of 5 ppmv for Boilers and 9 ppmv for Process Heaters. A provision was added for any Process Heater that is less than 40 MMBtu/hour with a high NOx concentration limit greater than 75 ppmv. Under this provision, the operator can use a NOx Concentration of 40 ppmv for the Final Phase BARCT Emission Target. Staff is aware of only one such Unit and this provision is designed to encourage the operator to reduce the NOx Concentration Limit in Phase I of the I-Plan.

Mass Emission Demonstration for an I-Plan with B-Plan or I-Plan with Table 1 or Table 2 – Paragraph (h)(5)
Paragraph (h)(5) establishes the requirements that an operator that elects to implement an I-Plan and a B-Plan, or an I-Plan to meet the NOx Limits in Table 1 and or Table 2 must demonstrate that the BARCT Equivalent Mass Emissions are less the Facility BARCT Emission Target for each phase of the I-Plan.

Mass Emission Demonstration for an I-Plan with B-Cap – Paragraph (h)(6)
Paragraph (h)(6) establishes the requirements that an operator that elects to implement an I-Plan and a B-Cap must demonstrate that the BARCT B-Cap Annual Emissions are less than the Facility BARCT Emission Target for each phase of the I-Plan.

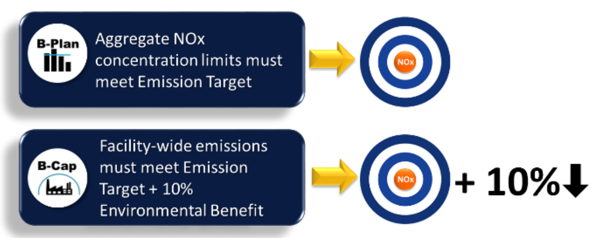
Compliance with an I-Plan without a B-Plan or B-Cap – Paragraph (h)(7)
Paragraph (h)(7) establishes the requirements that an operator that elects to implement an I Plan without a B-Plan or B-Cap shall meet the NOx Concentration Limits and Corresponding CO Concentration Limits in Table 1 or Table 2 based on the schedule in the approved I-Plan.

Compliance with an I-Plan with B-Plan – Paragraph (h)(8)
Paragraph (h)(7) establishes the requirements that an operator that elects to implement an I-Plan and a B-Plan shall meet the Alternative BARCT NOx Concentration Limits in an approved B-Plan based on the schedule in the approved I-Plan.

Requirements for Implementing an I-Plan – Paragraph (h)(9)
Paragraph (h)(8) establishes the requirements for operators that are implementing an I-Plan with a B-Cap which includes the following:

- Meet the Alternative BARCT NOx Concentration Limits and decommission any Units in an approved B-Cap, and implement other emission reduction strategies to achieve the Facility BARCT Emission Target for each phase, based on the schedule in the approved I-Plan;
  Demonstrate daily compliance that mass emissions from all Units in the I-Plan are below the Facility BARCT Emission Target for each phase of the I-Plan, based on a 365-day rolling average as measured pursuant to subdivisions (k) or subparagraph (n)(2)(C), based on the applicable schedule in subparagraph (h)(8)(C) or (h)(8)(D);
- Meet the Phase I and Phase II Facility BARCT Emission Targets of I-Plan Option 3 for:
  - The Baseline Facility Emissions before January 1, 2031, only if the Facility is a Former RECLAIM Facility;
  - Phase I Facility BARCT Emission Target on and after January 1, 2031 and before January 1, 2035; and
  - Phase II Facility BARCT Emission Target on and after January 1, 2035; and
- Meet the Phase I, Phase II, and Phase III Facility BARCT Emission Targets of I-Plan Option 4 for:
  - The Baseline Facility Emissions before January 1, 2025, only if the Facility is a Former RECLAIM Facility;
  - Phase I Facility BARCT Emission Target on and after January 1, 2025 and before July 1, 2030;
  - Phase II Facility BARCT Emission Target on and after July 1, 2030 and before July 1, 2033; and
  - Phase III Facility BARCT Emission Target on and after July 1, 2033.

10 Percent Environmental Benefit for the B-Cap – Subparagraph (h)(4)



The South Coast AQMD has the obligation to ensure that PR 1109.1 can be approved by CARB and U.S. EPA to be incorporated into the State Implementation Plan (SIP). Staff has discussed the provisions of the B-Cap with both agencies, and they concur that the additional 10 percent reduction in the BARCT facility emission target is appropriate for the B-Cap. Since the B-Cap establishes a mass emissions cap compliance option, the Final Phase Facility BARCT Emission Target for the B-Cap is proposed to be reduced by an additional 10 percent. Based on discussions with U.S. EPA and review of U.S. EPA's January 2001 guidance for EIPs titled "Improving Air Quality with Economic Incentive Programs" the B-Cap is an Economic Incentive Program because it is both a source-specific cap and a trading EIP and does require an environmental benefit. U.S. EPA agrees that a 10 percent reduction in NOx is the most appropriate environmental benefit approach for the B-Cap. For additional details regarding the 10 percent environmental benefit, please refer to the Response to Comments.

Two Compliance Components of the B-Cap (Subparagraphs (h)(9)(A) and (h)(9)(B))

Under the B-Cap, there are two compliance components. The first component establishes and incorporates in a permit, the Alternative BARCT NOx Limit which will be based on the averaging time for the specific equipment category in Table 1 or Table 2. The second is the demonstration that actual mass emissions from all Units under the B-Cap are below the Facility BARCT Emission Target. Under the B-Cap, the BARCT Equivalent Mass Emissions, which is the sum of the emissions for each Unit emission reduction projects, including those to meet the Alternative BARCT NOx Limit, decommissioned Units, or other reduction strategies must be implemented for each phase of the I-Plan, and the operator must demonstrate that the NOx mass emissions for all Units in the I-Plan and B-Cap will be lower than the Facility BARCT Emission Target for each phase. Operators are required to conduct a daily 365-day demonstrations that the measured NOx emissions at the facility are below the Facility BARCT Emission Target for each phase of the I-Plan. Because this requirement is based on a 365-day average, a full year of data is needed to collect the first daily average. The effective date when an operator is required to demonstrate that the annual emissions are below the Facility BARCT Emission Target is 365 days after the B-Cap Effective Compliance Date of the Facility BARCT Emission Target in Table 6, however, the first day that used in the 365-day rolling average is the B-Cap Effective Compliance Date of the Facility BARCT Emission Target. The following provides the schedule of the effective dates for the two I-Plan options for operators with a B-Cap. These dates reflect first day in which daily demonstration is required to show that based on the 365-day rolling average, NOx mass emissions from all Units in the I-Plan and B-Cap are less than the Facility BARCT Emission Target for each phase of the I-Plan. Prior to implementation of the first phase, operators will be subject to the Baseline Facility Emissions upon exiting RECLAIM. Operators will not be subject to the Facility BARCT Emission Target for Phase I, Phase II, and if applicable Phase III until the facility exits RECLAIM and becomes a former RECLAIM facility.

Table 3-9. Compliance Demonstration Dates for the Facility BARCT Emission Target for I-Plans and B-Cap

I-Plan Option	Baseline Facility Emissions	Phase I	Phase II	Phase III
I-Plan Option 3	Before January 1, 2021, only if Facility is a Former RECLAIM Facility	On and after January 1, 2031 and before January 1, 2035	On and after January 1, 2035	Not Applicable
I-Plan Option 4	January 1, 2025, only if the Facility is a Former RECLAIM Facility	On and after January 1, 2025 and before July 1, 2030	On and after July 1, 2030 and before July 1, 2033	On and after July 1, 2033

SUBDIVISION (i) – I-PLAN, B-PLAN, AND B-CAP SUBMITTAL AND APPROVAL REQUIREMENTS

I-Plan, B-Plan, and B-Cap Submittal and Approval Requirements

This subdivision specifies the submittal, and review and approval requirements for the I-Plan, B-Plan, and B-Cap. Submittal requirements for the I-Plan, B-Plan, and B-Cap are provided in paragraphs (i)(1), (i)(2), and (i)(3), respectively.

B-Plan and B-Cap Submittal – Paragraphs I-Plan Submittal Requirements – paragraph (i)(1)

This paragraph includes the submittal requirements for facilities complying with an alternative schedule in the I-Plan. On or before September 1, 2022 a facility may elect to submit an I-Plan identifying which units will be part of the plan and I-Plan option selected.

For many units, the Unit BARCT B-Cap Emissions will be lower than the BARCT Equivalent Mass Emissions for individual Units since compliance demonstration for the mass emissions cap for the B-Cap is based on a 365-day average as compared to shorter averaging times required for the Alternative NOx BARCT Emission Limits which are largely based on Table 1. PR 1109.1. This provision requires operators to provide an explanation when there is this differential. Acceptable reasons can be the averaging time, built-in compliance margin for Alternative BARCT NOx Limit, changes in capacity or use of the Unit, or any other emission reduction strategy.

B-Plan and B-Cap Submittal Requirements – paragraphs (i)(2) and (i)(3)

Submitted B-Plan and B-Cap must meet specific criteria to be considered complete:

- The device identification number and description,
- Alternative BARCT NOx limits for each unit that will cumulatively meet the Facility BARCT Emission Target

ALTERNATIVE BARCT NOx LIMIT FOR PHASE I, PHASE II, OR PHASE III is the unit specific NOx concentration limit that is selected by the owner or operator to achieve the Phase I, Phase II, or Phase III Facility BARCT Emission Target in the aggregate in the B-Plan or B-Cap, where the NOx concentration limit will include the corresponding percent O_2 correction and determined based on the averaging time in Table 1 or subdivision (k), whichever is applicable.

PHASE I, PHASE III, OR PHASE III BARCT B-CAP ANNUAL EMISSIONS means the total NOx mass emissions remaining per Facility that incorporates BARCT Alternative NOx Limits for Phase I, Phase II, and Phase III, decommissioned units, and other emission reduction strategies to meet the respective Phase I, Phase II, or Phase III Facility BARCT Emission Targets in an I-Plan and are calculated pursuant to Attachment B of this rule.

PHASE I, PHASE II, OR PHASE III BARCT EQUIVALENT MASS EMISSIONS means the total NOx mass emissions remaining per Facility that incorporates respective BARCT Alternative NOx Limits for Phase I, Phase II, and Phase III in an approved B-Plan that are designed to meet the respective Phase I, Phase II, or Phase III Facility BARCT Emission Targets in an I-Plan and are calculated pursuant to Attachment B of this rule.

For the purpose of B-Plan, the Alternative BARCT NOx limits is the concentration limit determined by the facility for each of the included units in the plan in a manner that the facility achieves the Facility BARCT Emission Target in aggregate. For the purpose of B-Cap, the Alternative BARCT NOx limits combined with other emission reduction strategies are used to determine the BARCT B-Cap Annual emissions.

For a B-Plan, the operator must demonstrate that the Phase I, Phase II, and Phase III BARCT Equivalent Mass Emissions is equal to or less than the respective Phase, I, Phase II, and Phase III Facility BARCT Emission Target. The BARCT Equivalent Mass Emissions for each facility is the total mass emissions at full implementation of control projects and must be calculated based on the Alternative BARCT NOx limits using the equations in Attachment B in PR 1109.1 and using the NOx Concentration Limit listed in "Baseline NOx Emissions and Representative for Facilities Regulated Under Rule 1109.1 - Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations".

For a B-Cap, the operator must demonstrate that the Phase I, Phase II, and Phase III BARCT B-Cap Annual Emissions is equal to or less than the respective Phase, I, Phase II, and Phase III Facility BARCT Emission Target. The BARCT B-Cap Annual Emissions for each facility is the total mass emissions at full implementation of control projects and must be calculated based on the Alternative BARCT NOx limits and other emission reduction strategies as shown in Attachment B in PR 1109.1. Under a B-Cap, an owner or operator must achieve Alternative NOx Limits as well as demonstrate that the actual facility-wide emissions for all units in the B-Cap are at or below the Facility BARCT Emission Target. The unit specific emission limit is based on the averaging time specified in Table 1 for the applicable unit, however, the on-going compliance demonstration of facility-wide mass emissions are based on a rolling 365-day average, each day.

PHASE I, PHASE II, OR PHASE III FACILITY BARCT EMISSION TARGET means the total NOx mass emissions per Facility that must be achieved in an approved B-Plan or B-Cap that are based the percent reduction target of Phase I, Phase II, or if applicable, Phase III of an I-Plan option in Table 6 and are calculated pursuant to Attachment B of this rule.

Also, the owner or operator is required to demonstrate compliance with the previously approved I-Plan through using the equation specified under Attachment B of PR 1109.1 to show that the percent of emission reduction from either B-Plan or B-Cap is equal or more than the I-Plan Percent Reduction Targets for each phase per PR 1109.1 Table 4.

I-Plan, B-Plan, and B-Cap Review and Approval Process – Paragraph (i)(4)

Paragraph (i)(4) provides the criteria for evaluating the I-Plan, B-Plan, and B-Cap. The Executive Officer will notify the owner or operator if the submitted plan is approved or disapproved. Approval will be based on the criteria set forth in paragraph (i)(4). The I-Plan, B-Plan, and B-Cap are subject to disapproval if any of the criteria are not met. Each of the criteria is described below.

Timely Complete Submittal of an I-Plan, B-Plan, or B-Cap – Paragraph (i)(4)(A)

The completed plans must be submitted on or before September 1, 2022 and must include all information that is required to be submitted under subparagraphs (i)(1), (i)(2) and (i)(3). The Executive Officer will review this information to ensure it meets the submittal requirements, is complete, and accurate.

Identification of Units in the I-Plan, B-Plan, or B-Cap – Subparagraph (i)(4)(B)

The plans should be limited to units that qualify for the respective plan pursuant to subparagraph (h)(1)(B) and are located at the same facility or facilities with the same ownership. Subparagraph (h)(1)(B) either directly specifies or references the Units that must be included, optional, and Units that must be excluded for the various plans. Operators have the option to submit a plan for a single

Facility or Facilities With The Same Ownership. The operator must provide the device and device identification number for each Unit for each Facility or Facility With the Same Ownership.

Selecting an I-Plan Option – Subparagraph (i)(4)(C)
The operator must provide the I-Plan option selected. Selection of any I-Plan option must meet the requirements specified in paragraph (h)(2).

Baseline NOx Emissions and Representative NOx Concentrations - (i)(4)(D)
All calculations must use the Baseline NOx Emissions and Representative NOx Concentrations that were established through the process provided under paragraph (h)(3). A B-Plan, B-Cap, or I-Plan will not be approved if an operator uses Baseline NOx Emissions or Representative NOx Concentrations for any unit that are not in the approved "Baseline NOx Emissions and Representative NOx Concentrations for Facilities Regulated Under Rule 1109.1 Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations," or that meet the conditions for using a different value as allowed under paragraph (h)(3).

BARCT Equivalent Mass Emissions and Alternative BARCT NOx Limit (i)(4)(E)
The operator must demonstrate that the BARCT Equivalent Mass Emissions were calculated pursuant to Attachment B, and the use of Alternative BARCT NOx Limits selected when calculating the BARCT Equivalent Mass Emissions meets the requirements specified under subparagraph (g)(1)(C) for the B-Plan and subparagraph (g)(2)(C) for a B-Cap. The requirements under these referenced subparagraphs have limitations on the maximum concentration limit that can be selected for an Alternative NOx Limit and references requirements for Conditional NOx Concentration Limits that also has specific requirements regarding submitting a permit application and the maximum NOx Concentration Limit that can be used for the Alternative NOx Limit. For any Unit where an Alternative NOx Limit is not specified for a given phase, the operator must use the Representative NOx Concentration, which will equate to the Baseline NOx Emissions. All of these provisions must be satisfied for approval of an I-Plan, B-Plan, and B-Cap.

Facility BARCT Emission Target – Subparagraph (i)(4)(F)
One of the key elements of the I-Plan are establishing the Facility BARCT Emission Targets. The Facility BARCT Emission Targets are based on the Percent Reduction Targets for each phase that are applied to the overall NOx reductions and must be calculated for each phase pursuant to Attachment B of PR 1109.1. The total NOx reductions are based on the Final Phase BARCT Emission Target. The operator is required to only use NOx concentration limits for each unit pursuant to paragraph (h)(4), which specifies under what situations a Unit can use the Table 1 or Table 2 conditional NOx Concentration Limit. Part of the eligibility for using a Table 2 conditional NOx Concentration Limit is that the permit application was submitted on or before June 1, 2022. If an incorrect NOx concentration limit is used to calculate the Final Phase BARCT Emission Target, the I-Plan, B-Plan, or B-Cap would be disapproved.

Demonstration that BARCT Equivalent Mass Emissions are Less than the Facility BARCT Emission Target (B-Plan) – Subparagraph (i)(4)(G)
This provision is critical for approving an I-Plan that is using a B-Plan, or an I-Plan where an operator is meeting the Table 1 or Table 2 NOx Concentration Limits. Operators must demonstrate that the BARCT Equivalent Mass Emissions are below the Facility BARCT Emission Targets for each phase when taking into account the application of Alternative NOx Concentration Limits for each phase of the I-Plan. For the B-Plan, this review ensures that the Facility BARCT Emission Target is met based on the Alternative BARCT NOx limits that the operator identified for units

under the B-Plan. The submitted B-Plan must demonstrate Equivalent Mass Emissions for units to cumulatively meet the Facility BARCT Emission Target that is adjusted by the Percent Reduction Targets based on the selected I-Plan option and the applicable Implementation Schedule in PR 1109.1 Table 6, using the calculation method provided in PR 1109.1 Attachment B. This demonstration is required to approve the I-Plan and B-Plan, or of the I-Plan or B-Plan is modified.

Demonstration that BARCT B-Cap Annual Emissions are less than the Facility BARCT Emission Target (B-Cap) – Subparagraph (i)(4)(H)

For the B-Cap, the review ensures the BARCT B-Cap Annual Emissions are less than the Facility BARCT Emission Target, where BARCT B-Cap Annual Emissions can account for emission reductions associated with implementation of Alternative BARCT NOx limits, units that the operator has identified to be decommissioned, and other reductions. The operator is required to provide an explanation when the Unit BARCT B-Cap Annual Emissions are less than the BARCT B-Cap Annual Emissions. The operator must provide sufficient details to describe the differential to ensure the differential is reasonable taking into consideration information such as the type of Unit, anticipated future usage of the Unit, and current and future capacity of Unit, use of the Unit within existing and future operations, anticipated compliance margins, increased efficiency, etc. The submitted B-Cap must be prepared using the calculation method provided in PR 1109.1 Attachment B to demonstrate that Equivalent Mass Emissions for included units cumulatively meets the Facility BARCT Emission Target less 10 percent of the overall reductions required and then adjusted by the Percent Reduction Targets based on the selected I-Plan option and the applicable Implementation Schedule in PR 1109.1 Table 6.

Disapproval of an I-Plan, B-Plan, and B-Cap – Paragraphs (i)(5) and (i)(6)

If Executive Officer disapproves the initial I-Plan, B-Plan or B-Cap, the proposed rule considers a 45-day period for the owner or operator to resubmit a corrected plan. Upon re-submittal, the I-Plan, B-Plan, or B-Cap will be reviewed and approved if the criteria set forth in paragraph (i)(4) is met. If the applicable criteria are not met or there are deficiencies, the I-Plan, B-Plan, or B-Cap will be disapproved. Upon second disapproval of the plan by the Executive Officer, the owner or operator must comply with the emission limits in Table 1 or Table 2 of PR 1109.1 pursuant to the compliance schedule in the selected I-Plan option. An operator who is required to meet the compliance schedule under paragraph (e)(1), is not precluded from meeting NOx and CO Concentration Limits in Table 2, provided the requirements under paragraph (d)(6) for the conditional NOx and CO Concentration Limits were met.

Modification to an Approved I-Plan, Approved B-Plan, or Approved B-Cap – Paragraph (i)(7) and (i)(8)

Paragraph (i)(7) includes the procedure the facilities must follow to apply for a modification to their approved I-Plan, B-Plan or B-Cap. In addition, PR 1109.1 includes requirements for when an I-Plan, B-Plan and B-Cap shall be modified:

- A unit identified as meeting Table 2 no longer meets the requirements of subparagraph (d)(2)(A) or (d)(2)(B);
- A unit in an approved B-Cap or B-Plan, identified as meeting Table 2 for establishing the Phase I, Phase II, or Phase III BARCT Facility Emission Target, is decommissioned;
- A higher Alternative BARCT NOx Limit will be proposed in the South Coast AQMD permit application than the Alternative BARCT NOx Limit for that unit in the currently approved I-Plan, B-Plan, or B-Cap;

- Any emission reduction project is moved to a later implementation phase, any emission reduction project is moved between phases, or any emission reduction project is removed from a phase;
- The owner or operator receives written notification from the Executive Officer that modifications to the I-Plan, B-Plan, or B-Cap are needed; or
- A permit application is submitted for a New Unit that meets at least one provision of subparagraph (g)(2)(J).

Review and approval of modifications to an I-Plan, B-Plan, or B-Cap shall be based the initial review and approval process. Although there is no specified timeframe to submit a modification, the owner or operator is expected to submit a modification upon knowing one of the items under paragraph (i)(5) are triggered.

Notification of Pending Approval of an I-Plan, B-Plan, or B-Cap – Paragraph (i)(9)
PR 1109.1 requires the Executive Officer to make the I-Plan, B-Plan, or B-Cap or modifications to an approved I-Plan, B-Plan, or B-Cap available to the public on the South Coast AQMD website 30 days prior to approval. Purpose of this provision is to provide an opportunity for the public to view the I-Plan, B-Plan, or B-Cap prior to approval.

SUBDIVISION (j) – TIME EXTENSION

PR 1109.1 allows two primary types of time extensions: one for specific circumstances outside of the control of the owner or operator, and the second aims to address situations where an emission reduction project falls outside of a turnaround window due to the permitting process. This subdivision establishes the criteria for time extensions, information that must be submitted, and the approval process.

Under paragraph (j)(1), an operator may request one 12-month extension for each unit for specific circumstances outside the control of the owner or operator. The operator should provide sufficient detail to explain the amount of time up to 12 months that is needed to complete the emission reduction project. If the operator requests less than 12 months, the Executive Officer will accept a subsequent request provided the total time for previous extensions plus subsequent requests does not exceed 12 months. Such a request must be made in writing no later than 90 days prior to the compliance schedule specified in the approved I-Plan. The owner or operator must demonstrate that there are specific circumstances that necessitate the additional time requested to complete the emission reduction project. The operator must provide sufficient information to document the operator took the necessary steps to ensure the project would not be delayed with a description and documentation of why the project was delayed. PR 1109.1 establishes four main areas that will be evaluated: Delays related to missed milestones; delays due to other agency approvals; delays related to delivery of parts or equipment; and delays related to workers or services. More specifically, as required under subparagraph (j)(6)(C), information or documentation as to why there was a delay of key schedules, reasons for another agency's delay, purchase orders and invoices from vendors, as well as an explanation of the delay and additional time for contract workers and source testers.

For the second type of time extension, the amount of time allowed will be based on when the Permit to Construct was issued and the subsequent turnaround for the specific unit. An operator that requests a time extension for a turnaround under paragraph (j)(2) can also request a time extension under subparagraph (j)(1), provided the operator meets the criteria under that paragraph. The criteria for an extension for a turnaround are more specific and the operator must provide in writing at the time the permit application is submitted, the months and year(s) of the turnaround and the years for the subsequent turnaround. The Executive Officer will determine the time extension based on the current turnaround and the subsequent turnaround schedule. Other criteria are needed to ensure that in order to receive the extension, the issuance of the Permit to Construct does not align with the turnaround window because of the amount of time between the permit application submittal and issuance of the Permit to Construct. Approval of a time extension for a turnaround is based on the criteria set forth under subparagraph (j)(2)(C). Staff will assess the information and work with the operator to establish the appropriate timeframe of the extension taking into account the current turnaround and the subsequent turnaround.

Paragraph (j)(4) provides the required timeframes for a Facility to submit the written request for approval of a time extension and paragraph (j)(5) lists the specific information required such as the affected unit in which phase, the amount of extension time being requested, as well as the month and year of the turnaround if that is a reasoning for the extension.

If there is additional information needed to substantiate the request for a time extension, the Executive Officer may request additional information. This provision is to allow the operator the opportunity to provide critical information needed to approve a time request. If the Executive Officer requests additional information, the operator must provide that information based on the timeframe specified by the Executive Officer. Approval of the time extension represents an amendment to the approved I-Plan, and the operators must adhere to the timeframe established in the approved time extension to meet the NOx and CO emission limit in PR 1109.1 Table 1, PR 1109.1 Table 2, approved B-Plan, or approved B-Cap. If the Executive Officer disapproves the time extension request, the applicable emission limits must be met within 60 calendar days after notification of disapproval is received.

Facilities implementing a B-Cap (paragraph (j)(3)) may request a time extension provided a Permit to Construct was issued more than 18 months after the permit application was submitted. This provides additional time when the project was delayed due to the delay in receiving a Permit to Construct. The extension is limited to no longer than the time difference between 18 months after the complete permit applications was submitted and when the Permit to Construct was issued. Paragraph (j)(3) allows a facility with a B-Cap to request for an extension of the dates to meet the Facility BARCT Emission Target for reasons provided under paragraphs (j)(1) and (j)(2) discussed above

Paragraph (j)(4) provides the required timeframes for a Facility to submit the written request for approval of a time extension. Time extensions must be submitted no later than 180 days prior to a Compliance Date in paragraph (f)(1) or an approved I-Plan or 180 days prior to the effective date of the Facility BARCT Emission Target. This allows sufficient time for the extension to be evaluated.

Paragraph (j)(5) lists the specific information required such as the affected unit in which phase, the amount of extension time being requested, as well as the month and year of the turnaround if that is a reasoning for the extension. The time extension request shall include information needed to identify the Unit, time requested, and the reason for the extension under paragraph (j)(8). The Executive Officer will review the request based on information on key construction milestones missed, delays from agency review, delays related to the delivery of parts, or delays related to service providers for an extension related to circumstances beyond the control of the facility. For those related to a delay in receiving a Permit to Construct, dates when the application was submitted and when the Permit to Construct was issued. The length of the extension is determined based on limitations in paragraphs (j)(1) through (j)(3). An owner that receives an extension pursuant to paragraphs (j)(1) or (j)(2) shall meet the limits within the time frame in the approval. For an extension pursuant to paragraph (j)(3), the Facility BARCT Emission Target will be adjusted for each Unit where a time extension was approved.

Under paragraph (j)(10), for facilities under a B-Cap, time extensions to comply with the Facility BARCT Emission Target for individual unit projects will require an adjustment to the Facility BARCT Emission Target to ensure the facility continues to comply with B-Cap. Such an adjustment to the Facility BARCT Emission Target would be based on the reductions not yet achieved within the target due to time extension provided to that unit or units. Thus, until the unit reduces emissions as scheduled in the B-Cap, the Facility BARCT Emission Target would need to be temporarily increased. That increase would be based on the unit's emission levels from the previous phase, or if in Phase I, from the Baseline Unit Emissions. When the time extension expires, the unit should be achieving reduced emissions and the Facility BARCT Emission Target can reduced to the original levels as required by the I-Plan. The duration of the time extensions is provided in paragraph (j)(7).

SUBDIVISIONS (k) – CEMS REQUIREMENTS

This subdivision contains the CEMS requirements for the combustion equipment subject to PR 1109.1.

Units Requiring CEMS – Paragraphs (k)(1) through (k)(3)

For any unit that has a CEMS, or the owner or operator elects to use a CEMS to demonstrate compliance with the applicable PR 1109.1 NOx and Corresponding CO Concentration Limits, the installation and operation of CEMS must be in compliance with the applicable requirements of Rule 218.2 – Continuous Emission Monitoring System: General Provisions and Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications when it becomes a Former RECLAIM Facility. Units with a Rated Heat Input Capacity of greater than or equal to 40 MMBtu/hour and Sulfuric Acid Furnaces at Former RECLAIM Facilities are required to have NOx CEMS. Additionally, Sulfuric Acid Furnaces at Former RECLAIM Facilities are required to have an oxygen CEMS within 12 months of rule adoption. Units at a Former RECLAIM Facility with a CO CEMS on the date of rule adoption must continue to operate and maintain the CO CEMS pursuant to Rules 218.2 and 218.3 to demonstrate compliance with the applicable PR 1109.1 CO limits. PR 1109.1 requires these CO CEMS be certified within 12 months of rule adoption. Until that time, facilities will continue to be subject to Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions.

Invalid CEMS Data – Paragraph (k)(4)

Invalid data shall be excluded pursuant to Rule 2012 while the facility remains in RECLAIM and then excluded pursuant to Rules 218.2 and 218.3 once the facility becomes a Former RECLAIM Facility.

Missing Data Procedures – Paragraph (k)(5)

For Facilities with an approved B-Cap with a certified CEMS that is not collecting data, the missing data calculation is based on the length of the missing data period. If the missing data period is less than 8 hours, the missing data shall be calculated using the hourly data immediately before and after the missing period. If the missing data period is more than 8 hours, the missing data shall be calculated using the maximum hourly data from the past 30 days; the 30 days begins on the day immediately before the day of the missing data occurred. It is assumed that shorter missing data periods would be similar to the most recent operational data. However, that assumption is no longer as likely during long outages and thus the worst case will be attributed to the missing data period. Missing data is only applicable to facilities utilizing a B-Cap.

SUBDIVISIONS (l) – SOURCE TEST REQUIREMENTS

This subdivision contains the source testing requirements for the combustion equipment subject to PR 1109.1.

Requirements for Source Testing – Paragraph (l)(1)

For any Unit without CEMS, compliance with the applicable PR 1109.1 NOx and Corresponding CO Concentration Limits and percent of oxygen must be demonstrated by conducting a source test according to PR 1109.1 Table 7 or Table 8. The source test subdivision has two compliance schedules, subparagraph (l)(1)(A) for Units with no ammonia in the exhaust (e.g., units without SCR) and subparagraph (l)(1)(B) for Units with ammonia in the exhaust. These paragraph also include the required averaging time for Units that are required to demonstrate compliance with PR 1109.1 concentration limits based on a source test; all Units that are not required to install and maintain CEMs must demonstrate compliance based on a source test protocol with an averaging time duration between 60 to 120 minutes.

PR 1109.1 subparagraph (l)(1)(A) requires Units that do not require CEMS and do not vent to air pollution control equipment with ammonia injection to demonstrate compliance with the PR 1109.1 NOx and CO Concentration Limits pursuant to the source test schedule in Table 7. For an owner or operator of a Unit not required to install and operate a CEMS that vents to air pollution control equipment with ammonia injection, paragraph (l)(1)(B) requires compliance with the PR 1109.1 NOx and CO Concentration Limits and the established ammonia South Coast AQMD permit limit (permit limit) to be demonstrated according to the source test schedule in Table 8. The source test schedules in Tables 7 or Table 8 vary depending on the which CEMS the Facility has for the different pollutants being measured (e.g., NOx, CO, or ammonia). When more than one pollutant requires source testing, Tables 7 and 8 require simultaneous source testing. Conducting a NOx, CO, and ammonia source test simultaneously is important as the pollutants have an inverse relationship and it is critical that all pollutants are meeting the limits.

Source Test Schedule for Units Without Ammonia Injection – PR 1109.1 Table 7

The table below has the source test schedules for Units with ammonia emissions in the exhaust. The source test schedule for these Units is divided into two categories dependent on combustion equipment: 1.) Vapor Incinerators less than 40 MMBtu/hr and Flares; and 2.) all other Units. These two categories are further divided, dependent on what type of CEMS the Unit has: A.) Units operating without NOx or CO CEMS, B.) Units operating with NOx CEMS and without CO CEMS, and C.) Units operating without NOx CEMS and with CO CEMS. Vapor incinerators typically operate intermittently and are overall low emitters so source testing every 3 years is a reasonable check on their performance. Other units, such as boilers and heaters <40 MMBTU/hr, operate more frequently so have higher emission potential thus, more source testing on an annual basis.

Source Test Schedule for Units with Ammonia Injection – PR 1109.1 Table 8

The table below has the source test schedules for Units with ammonia emissions in the exhaust. The source test schedule for these Units is divided into five categories dependent on what type of CEMS the Unit has: A.) Units operating without NOx, CO, or ammonia CEMS, B.) Units operating with NOx CEMS and without CO or ammonia CEMS, C.) Units operating with NOx and CO CEMS and without ammonia CEMS, D) Units operating with NOx and ammonia CEMS and without CO CEMS, E) Units operating with ammonia CEMS and without NOx or CO CEMS, F) Units operating with ammonia and CO CEMS and without NOx CEMS, and G) Units operating with CO CEMS and without a NOx or ammonia CEMS. Tests are initiated within 12 months after compliance with applicable NOx and CO concentration limits, and, if applicable an ammonia permit limits, and annually afterwards for those pollutants not monitored with a CEMS. If the annual tests exceed the concentration limits, then four consecutive quarterly tests are required to demonstrate compliance before resuming the annual testing schedule.

Table 3-10. PR 1109.1 Table 7 – Source Testing Schedule for Units without Ammonia Emissions in the Exhaust

CEMS Status	Source Test Schedule
Vapor Incinerators <40 MMBtu/hr and Flares	
Units Operating without NOx and CO CEMS	• Conduct simultaneous source tests for NOx and CO within 12 months of being subject to applicable NOx and CO concentration limits and every 36 months thereafter
Units Operating with NOx CEMS and without CO CEMS	• Conduct a source test for CO within 12 months of being subject to applicable NOx and CO concentration limits and every 36 months thereafter
Units Operating without a NOx CEMS and with a CO CEMS	• Conduct a source test for NOx within 12 months of being subject to applicable NOx and CO concentration limits and every 36 months thereafter

CEMS Status	Source Test Schedule
All Other Units	
Units Operating without NOx and CO CEMS	• Conduct simultaneous source tests for NOx and CO quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx and CO concentration limits • If an annual source test demonstrates an exceedance of applicable NOx or CO concentration limit, four consecutive quarterly source tests must demonstrate compliance with the applicable NOx and CO concentration limits prior to resuming annual source tests
Units Operating with NOx CEMS and without CO CEMS	• Conduct a source test for CO within 12 months of being subject to applicable NOx and CO concentration limits and annually thereafter
Units Operating without NOx CEMS and with CO CEMS	• Conduct a source test for NOx quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx concentration limit • If an annual source test demonstrates an exceedance of a NOx concentration limit, four consecutive quarterly source tests must demonstrate compliance with the NOx concentration limit prior to resuming annual source tests

Table 3-11. PR 1109.1 Table 8 – Source Testing Schedule for Units with Ammonia Emissions in the Exhaust

CEMS Status	Source Test Schedule
Units Operating without NOx, CO, and Ammonia CEMS	• Conduct simultaneous source tests for NOx, CO, and ammonia quarterly during the first 12 months of being subject to applicable NOx concentration and CO concentration limit • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx and CO concentration limits, and ammonia permit limit • If an annual source test demonstrates an exceedance with the NOx concentration limit, CO concentration limit, or ammonia permit limit, four consecutive quarterly source tests must demonstrate compliance with the applicable NOx and CO concentration limits, and ammonia permit limit prior to resuming annual source tests
Units Operating with NOx CEMS and without CO and Ammonia CEMS	• Conduct simultaneous source tests for CO and ammonia quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits, if four consecutive quarterly source tests demonstrate compliance with the CO concentration limit and ammonia permit limit • If an annual source test demonstrates an exceedance with a CO concentration limit or ammonia permit limit, four consecutive quarterly source tests must demonstrate compliance with the CO concentration limit and ammonia permit limit prior to resuming annual source tests

CEMS Status	Source Test Schedule
Units Operating with NOx and CO CEMS and without Ammonia CEMS	• Conduct a source test for ammonia quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the ammonia permit limit • If an annual source test demonstrates an exceedance with the ammonia permit limit, four consecutive quarterly source tests must demonstrate compliance with the ammonia permit prior to resuming annual source tests
Units Operating with NOx and Ammonia CEMS and without CO CEMS	• Conduct a source test for CO within 12 months of being subject to applicable NOx and CO concentration limits and annually thereafter
Units Operating with Ammonia CEMS and without NOx and CO CEMS	• Conduct simultaneous source tests for NOx and CO quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx and CO concentration limits • If an annual source test demonstrates an exceedance of applicable NOx concentration limit or CO concentration limit, four consecutive quarterly source tests must demonstrate compliance with the NOx and CO concentration limits prior to resuming annual source tests

CEMS Status	Source Test Schedule
Units Operating with CO and Ammonia CEMS and without NOx CEMS	• Conduct a source test for NOx quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx concentration limit • If an annual source test demonstrates an exceedance with the NOx concentration limit, four consecutive quarterly source tests must demonstrate compliance with the applicable NOx concentration limit prior to resuming annual source tests
Units Operating with CO CEMS and without NOx and Ammonia CEMS	• Conduct simultaneous source tests for NOx and ammonia quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx concentration limit and ammonia permit limit • If an annual source test demonstrates an exceedance of applicable NOx concentration limit or ammonia permit limit, four consecutive quarterly source tests must demonstrate compliance with the NOx concentration and ammonia permit limit limits prior to resuming annual source tests

Annual Source Test – Paragraph (l)(2)

The annual source test must be conducted every calendar year, but not sooner than six months from the previous source test. If the Unit has not operated for at least six consecutive calendar months, the annual source test is due no later than 90 days after the date of resumed operation and the owner or operator must demonstrate that the Unit has not been operated by using a non-resettable fuel meter to maintaining monthly fuel usage records.

CEMS In Lieu of Source Testing – Paragraph (l)(3)

This provision clarified that if an owner or operator elects to operate a CEMS in lieu of conducing source testing, the CEMS needs to meet the requirements in subdivision (k).

Initial Compliance Demonstration for New or Modified Units – Paragraph (l)(4)

The PR 1109.1 requirement for initial compliance demonstration of a new or modified unit is dependent on the averaging time of the Unit. Units with an averaging time less than 120 minutes are required to conduct an initial source test within six months from commencing operation and afterward, pursuant to the applicable schedule in PR 1109.1 Table 7 or Table 8. Units with an averaging time greater than 120 minutes as required by Table 1 or Table and Units required to adjust the NOx span range are required to demonstrate initial compliance through maintaining and operating a certified CEMS.

Submitting a Source Test Protocol and Timing of Source Test – Paragraph (l)(5)

PR 1109.1 requires the owner or operator to submit the complete source test protocol, that includes an averaging time of no less than 60 minutes but no longer than 120 minutes, to the South Coast AQMD Executive Officer for approval at least 60 days prior to conducting the source test, unless otherwise approved by the Executive Officer. The source test must be conducted within 90 days after the source test protocol has been approved by the Executive Office. A complete source test protocol should contain, but not limited to, reason for the source test, Permit to Construct or Permit to Operate, process description, sampling and analytical methods, process schematics, sampling location and related dimensions, and quality assurance procedures.

Source Test Notification – Paragraph (l)(6)

The owner or operator must notify the Executive Officer of the source test date at least one week prior to conducting the source test by calling 1-800-CUT-SMOG. The notification shall include facility name and identification number, device identification number, and the source test date.

Subsequent Source Test Protocols – Paragraph (l)(7)

Any source test conducted after the approval of the initial source test protocol does not require another approved source test, unless requested by the Executive Officer, if the method of operation of the Unit has not changed in a manner which would require a permit update, the proposed rule or permit concentration limits have not become more stringent, the referenced source test method(s) has not changed, and the approved source test protocol is representative of the Unit's operation and configuration, unless requested by the Executive Officer.

Conducting the Source Test – Paragraph (l)(8)

Upon approval of the source test protocol, the source test must be conducted using a South Coast AQMD approved contractor under the Laboratory Approval Program, during normal operating conditions and not during startup and shutdown, and using the applicable test methods:

- South Coast AQMD Source Test Method 100.1 – Instrumental Analyzer Procedures for Continuous Gaseous Emission Sampling; or
- South Coast AQMD Source Test Method 7.1 – Determination of Nitrogen Oxide Emissions from Stationary Sources and South Coast AQMD Source Test Method 10.1 – Carbon Monoxide and Carbon Dioxide by Gas Chromatograph/Non-Dispersive Infrared Detector (GC/NDIR) – Oxygen by Gas Chromatograph-Thermal Conductivity (GC/TCD);
- South Coast AQMD Source Test Method 207.1 – Determination of Ammonia Emissions from Stationary Sources; or
- Any other test method determined to be equivalent and approved by the Executive Officer, and either the California Air Resources Board or the U. S. Environmental Protection Agency, as applicable.

Vapor Incinerators – Paragraph (l)(9)

For Vapor Incinerators, demonstration that the Unit meets the applicable NOx Concentration Limit may be based on the NOx emission from only the burner and does not need to include the waste stream being directed to the Unit.

Source Test Reports – Paragraph (l)(10)

Source test reports shall be submitted to the Executive Officer within 90 days of the completed source test and shall include the source test results and the Unit's description.

Source Test Reports – Paragraphs (l)(11) and (l)(12)

If a source test demonstrates that a PR 1109.1 limit has been exceeded, that exceedance is considered a violation or PR 1109.1 and the owner or operator shall inform the Executive Officer within 72 hours of knowledge or when the owner or operator should have reasonably known of the exceedance.

SUBDIVISION (m) – DIAGNOSTIC EMISSION CHECKS

This subdivision contains the requirements for diagnostic emission checks which is required for any unit performing a source test every 36 months. The provisions provide the protocol to conduct the 30-minute diagnostic checks and the applicable schedule based on the corresponding source test schedule provided in this subdivision.

If emissions are measured in excess of an applicable PR 1109.1 emission limit or a permit condition using a diagnostic emissions check, this would not be considered a violation if an owner or operator corrects the problem and demonstrates compliance with the proposed rule using another diagnostic emissions check within 72 hours from the time they knew of excess emissions or shut down the unit by the end of an operating cycle.

SUBDIVISION (n) – MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS

This subdivision contains the provisions for monitoring and recordkeeping for CEMS and source test records; diagnostic emission checks; startup and shutdown logs; the details of interest from either of the activity logs; and the required sequence of recordkeeping and reporting.

Facilities that utilize a B-Cap shall report daily facility-wide emissions based on CEMS data on a monthly basis. For units that do no utilize a CEMS, daily emissions shall be determined by use an enforceable method approved by the Executive Officer, such as source test results and non-resettable totalizing fuel or time meter. Additionally, daily records for units included in an approved B-Cap shall include emissions during startups, shutdowns, maintenance, and times where the CEMS data was missing or invalid. This data shall be used on a daily basis to demonstrate compliance with the B-Cap. This subdivision has a reporting provision for the owner or operator of boilers and process heaters included in a B-Plan that will meet either the Interim NOx and CO Concentration Limits in Table 4 of PR 1109.1 or the Interim NOx concentration limit of 0.03 lb/MMBtu based on a daily rolling 365-day average upon exiting RECLAIM.

Units which are exempted from compliance with NOx and CO emission limits per PR 1109.1 are required to conduct monitoring, recordkeeping and reporting and the corresponding provisions (method and schedule) are included in this subdivision.

The owner or operator of a boiler or process heater less than 40 MMBtu/hour or a unit complying with a conditional limit in PR 1109.1 Table 2 is required to maintain records of burner replacement, including number of burners and date of installation. Recordkeeping will ensure compliance with the requirement that the owner or operator of a unit complying with a conditional limit in PR 1109.1 Table 2 must meet Table 1 emission limits upon replacement of the post-combustion equipment. Subdivision (m) includes provision requiring the owner to maintain records of the dates the existing post-combustion control equipment was installed or replaced.

Vapor incinerators utilizing the exemption in paragraph (o)(9) what keep records of annual throughput and emissions.

Burner replacement, including date of replacement and number of burners, shall be recorded to confirm compliance the compliance schedule in paragraph (f)(2) that is triggered when 50 percent or more of the burners or 50 percent of the heat input is replaced.

Likewise, dates of installation or replacement of post-combustion air pollution control equipment shall be recorded to demonstrate compliance with subparagraph (f)(4)(A).

Monitoring, recordkeeping and reporting requirements for the gas turbines during Natural Gas curtailment periods are also provided under this subdivision.

Within 60 days of becoming a Former RECLAIM Facility, a list of Boilers and Process Heaters shall be submitted identifying which units will meet the Table 4 limits and which will meet Interim NOx emission rate.6

SUBDIVISION (o) – EXEMPTIONS

This subdivision includes provisions for specific combustion units which are exempted from compliance with NOx and CO emission limits under low-use, low-emitting, or operating under specific conditions. The following are the Rule 1109.1 exemptions.

Boilers and Process Heaters with rated heat input capacity of 2 MMBtu/hour or less – Paragraph (o)(1)

Small boilers and process heaters (with rated heat input capacity of less than or equal to 2 MMBtu per hour) used for comfort heating that are not used in processing units, are exempt from PR 1109.1. Small natural gas-fired water heaters, boilers, and process heaters (with rated heat input capacity of less than or equal to 2 MMBtu/hr) at PR 1109.1 facilities will be regulated under Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters regulate boilers and heaters.

Low-Use Boilers – Paragraph (o)(2)

Low-use boilers with rated heat input capacity of less than 40 MMBtu/hour that are operated at less than 200 hours per calendar year, are exempt from the emission limits in Table 1 or Table 2. Low-use units have low emissions and high cost-effectiveness to retrofit. Facilities that elect to comply with a B-Plan or B-Cap must have a permit condition limiting operating hours, include the low-use units in the approved B-Plan or B-Cap, conduct source tests pursuant to Rule 1109.1 Table 7 or Table 8, and conduct diagnostic emission checks.

Low-Use Boiler and Process Heaters – Paragraph (o)(3)

Low-use boilers and process heaters with rated heat input capacity of 40 MMBtu/hour or greater that are fired at less than 15 percent of the rated heat capacity per calendar year, are exempt from the emission limits in Table 1, Table 2, or an approved B-Plan. The exemption will be determined based on 15 percent of the fuel use as if the Unit were operated at the Maximum Rated Heat Capacity (e.g., a Unit can only burn up to 15 percent of the maximum fuel the burner could fire if it fired at 100 percent of the Maximum Rated Heat Capacity for 8760 hours per year). Such unit is required to accept a South Coast AQMD permit to operate with a condition that limits the firing rate of the unit to 15 percent of the Rated Heat Input Capacity per year. Low-use units have low emissions and high cost-effectiveness to retrofit. Low-use units will still be subject to all of the other applicable provisions in the rule, must be included in an approved B-Cap (if applicable), and subject to interim emission limits.

FCCU exemption provisions – Paragraphs (o)(4) and (o)(5)

There are several exemption provisions for FCCUs. The first provision is to address boiler inspections required under California Code of Regulations, Title 8, Section 770(b). Some FCCUs with a CO boiler have to by-pass their SCR to safely conduct the inspection and without control an exemption from the emission is needed. For those units, PR 1109.1 provides an exemption from the applicable emission limits.

There is also an exemption for process heaters used to startup the FCCU provided the process heaters is operated for 250 hours or less per calendar year. Facilities that elect to comply with a B-Plan or B-Cap must include such process heater in the approved B-Plan or B-Cap, conduct source tests pursuant to Rule 1109.1 Table 7 or Table 8, and conduct diagnostic emission checks. The unit will have to accept a permit limit with a 250 hour per year or less operating limitation.

Startup and Shutdown Boilers and Process Heaters for Sulfuric Acid Plants– Paragraph (o)(6)

Boilers used for startup and shutdown operations at a sulfuric acid plant are also low-use units that will be exempt from applicable emission limits because to control would not be cost effective. The exemption is based on the current permit limitation which limits the boilers to 90,000 MMBtu of annual heat input per calendar year or less. Startup and Shutdown Boilers that are not included in an approved B-Plan or B-Cap are also exempt from CEMS, source testing, and diagnostic emission checks.

Pilot Exemption for Boilers and Process Heaters – Paragraph (o)(7)

The emission from boilers and process heater operating only the pilot during startup or shutdown are exempt from the applicable emission limits due to low emissions and not cost effective to control.

Flare Exemptions – Paragraph (o)(8)

Non-refinery flares that emit less than or equal to 550 pounds of NOx per calendar year are exempt from the applicable emission limits provided the unit accepts a permit condition with a 550 pound of NOx per year limit. These units are not cost effective to control or replace at this time. Open flares are also exempt from the source test requirement; because there is no stack, these units cannot be source tested.

Vapor Incinerator Exemptions – Paragraph (o)(9)

Vapor incinerators with Rated Heat Input Capacity of 2 MMBtu/hour or less also have a low-emitting exemption if they emit less than 100 pounds of NOx per calendar year. These units are not cost effective to control or replace at this time. Vapor incinerators with Rated Heat Input Capacity of 2 MMBtu/hour or less that emit less than 1000 pounds but more than 100 pounds of NOx per calendar year have a low-emitting exemption until the Unit is replaced or within ten years after date of adoption, whichever happens is sooner. Both classes of vapor incinerators are required to accept a South Coast AQMD permit to operate with a condition that limits the emissions from these units to the applicable level.

PR 1109.1 ATTACHMENT A – SUPPLEMENTAL CALCULATIONS

This attachment includes calculations for the rolling average calculation for emissions data averaging and the interim NOx emission rate calculation and I-Plan Option 3 emission rate calculation for boilers and heaters greater than or equal to 40 MMBtu/hour or boilers and heaters less than 40 MMBtu/hour that operate with a certified CEMS.

PR 1109.1 ATTACHMENT B – CALCULATION METHODOLOGY FOR THE I-PLAN, B-PLAN, AND B-CAP

This attachment includes calculations for the Baseline Emissions; Base Facility BARCT Emission Target; Phase I, Phase II, and Phase III Facility BARCT Emission Target; and Phase I, Phase II, and Phase III BARCT Equivalent Mass Emissions for a B-Plan and B-Cap.

Example 3-1: Example Calculations for Refinery X

Refinery X has more than six combustion units. This example will go through the steps of how the Phase I, Phase II, and if applicable, Phase II Facility BARCT Emission Targets are established and how this sample facility will demonstrate compliance through a B-Plan or a B-Cap.

Calculating the Baseline Facility Emissions

The table below provides for each unit, the Device Identification Number (Device ID), if the units have combined stacks, the equipment category, size, Baseline Unit Emissions, and Representative NOx concentration in ppmv. The Baseline Facility Emissions are the sum of all of the Baseline Unit Emissions for each device.

Table 3-12. Calculating the Baseline Facility Total

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)
D1	D1	Heater	320	245	100
D2	D2	Boiler	210	126	38
D3	D3	SMR Heater	450	97	48
D4	D4	FCCU		83	11
D5	D5	Heater	290	54	18
D6	D6	Heater	135	29	33
D7	D7	Heater	80	24	65
D8	D8	Heater	67	14	48
D9	D9	Heater	108	12	22
D10	D10	Boiler	330	11	10
D11	D11 and D12	Heater	75	8	16
D12	D11 and D12	Heater	75	8	16
D13	D13	Heater	64	3	8
D14	D14	Thermal Oxidizer	4	3	43
D15	D15	Heater	17	3	12
D16	D16	Sulfur Recovery Unit	40	10	35
Baseline Facility Emissions		Baseline Facility Emissions		**730**	

Calculating the Final Phase Facility BARCT Emission Target

For the purpose establishing the Final Phase Facility BARCT Emission Target, the operator will select either Table 1 or Table 2. Operators can only select Table 2 for establishing the Final Phase Facility BARCT Emission Target if the unit will meet the conditions under paragraph (d)(2). Operators that are selecting Table 2 emission limits must have submitted a permit application on or before July 1, 2022 that would establish NOx limit that would be at or below the NOx limit in Table 2 for the applicable unit.

The Final Phase Facility BARCT Emission is calculated using the following equation from PR 1109.1 Attachment B:

$$\text{Final Phase Facility BARCT Emission Target} = \sum_{i=1}^{N} \left(\frac{C_{\text{Table 1 or Table 2}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions} \right)_i$$

Where:

N	=	Number of included units in B-Plan or B-Cap
$C_{\text{Table 1 or Table 2}}$	=	The applicable NOx concentration limit for each unit i included in B-Plan or B-Cap
C_{Baseline}	=	The NOx concentration in the flue gas for unit i included in B-Plan or B-Cap as determined pursuant to section (B-2).
Baseline Unit Emissions	=	The 2017 NOx baseline emissions for unit i included in the I-Plan, or B-Plan or B-Cap as determined pursuant to section (B-1).

If a unit is qualified to meet PR 1109.1 Table 2 requirements per paragraph (d)(2) of the rule, the owner may decide to meet the applicable NOx limits in either Table 1 or Table 2 of PR 1109.1 for that unit. If the owner decides to meet PR 1109.1 Table 2 NOx limit for a unit, that limit will be included in the corresponding permit for that unit and the final remaining emissions for that unit is calculated based on the level of NOx on the permit (e.g., D11, D12, and D13 in the table below). The tables below show the process for determining how Table 1 and Table 2 NOx limits are applied. owner final selection of NOx limits for the units and the corresponding Final Phase Facility BARCT Emission.

Calculating the Emissions if Unit Meets Table 1 or Table 2 NOx Limits

In the next step, the NOx emissions are calculated assuming the unit meets Table 1 limits, and then calculated assuming the unit meets Table 2 limits. The Baseline Unit Emissions are ratioed by the Table 1 or Table 2 NOx concentration to the Representative NOx concentration.

Table 313. Calculating Emissions if Unit Meets Table 1 or Table 2 NOx Limits

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	PR 1109.1 Table 1 NOx Limit (ppmv)	PR 1109.1 Table 1 Remaining Emissions (Tons/Year)	PR 1109.1 Table 2 NOx	PR 1109.1 Table 2 Remaining Emissions (Tons/Year)
D1	D1	Heater	320	245	100	5.0	12.3	22.0	53.9
D2	D2	Boiler	210	126	38	[illegible]	16.6	7.5	24.9
D3	D3	SMR Heater	450	97	[illegible]	[illegible]	[illegible]	[illegible]	15.2
D4	D4	FCCU		83	[illegible]	[illegible]	[illegible]	[illegible]	60.4
D5	D5	Heater	290	54	[illegible]	[illegible]	[illegible]	[illegible]	66.0
D6	D6	Heater	135	29	[illegible]	[illegible]	[illegible]	[illegible]	19.3
D7	D7	Heater	80	24	65	5.0	1.8	18.0	6.6
D8	D8	Heater	67	14	48	5.0	1.5	18.0	5.3
D9	D9	Heater	108	12	22	5.0	2.7	18.0	9.6
D10	D10	Boiler	330	11	10	5.0	5.5	7.5	8.3
D11	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0
D12	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0
D13	D13	Heater	64	3	8	5.0	1.9	18.0	6.8
D14	D14	Thermal Oxidizer	4	3	43	30.0	2.1	40.0	2.8
D15	D15	Heater	17	3	12	9.0	2.3	N/A	N/A
D16	D16	Sulfur Recovery Unit	40	10	35	30.0	8.6	N/A	N/A
Baseline Facility Emissions				730					

NOx Emissions if Unit Meets 5 ppmv

NOx Emissions if Unit Meets 22

(Table 1 Limit/Representative NOx)*Baseline Unit Emissions) (5/100)*245)= 12.3 tons/year

(Table 2 Limit/Representative NOx)*Baseline Unit Emissions) (22/100)*245)= 53.9 tons/year

Pre-Screening Units for Table 2 Conditional NOx Limits

In this next step, South Coast AQMD will identify for operators those units that do not meet the conditions to use Table 2 NOx emission limits based on the potential NOx reductions. The potential NOx reductions are based on the difference between the Baseline Unit Emissions and the emissions if the unit met Table 1 (as calculated above). For the unit with a device identification number of "D1", the potential emission reductions are 232.7 tons/year (245 tons/year-12.3 tons/year). This is an initial pre-screening the operator must demonstrate that all of the conditions under paragraph (d)(2) are met before using a Table 2 NOx limit to calculate the Facility BARCT Emission Targets.

Table 314. Initial Pre-Screening for Eligibility for Table 2 Conditional Limits

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	PR 1109.1 Table 1 NOx Limit (ppmv)	PR 1109.1 Table 1 Remaining Emissions (Tons/Year)	PR 1109.1 Table 2 NOx Limit (ppmv)	PR 1109.1 Table 2 Remaining Emissions (Tons/Year)	Units Possibly Eligible for Conditional Limits Based on Potential Reductions (Refer to PR 1109.1 (d)(2) for all Conditions)
D1	D1	Heater	320	245	100	5.0	12.3	22.0	53.9	Not Eligible, Red > 20 TPY
D2	D2	Boiler	210	126	38	5.0	16.6	7.5	[illegible]	Not Eligible, Red > 20 TPY
D3	D3	SMR Heater	450	97	48	5.0	[illegible]	[illegible]	[illegible]	Not Eligible, Red > 20 TPY
D4	D4	FCCU		83	11	2.0	[illegible]	[illegible]	[illegible]	Eligible
D5	D5	Heater	290	54	18	5.0	15.0	22.0	66.0	Not Eligible
D6	D6	Heater	135	29	33	5.0	4.4	22.0	19.3	Not Eligible, Red > 20 TPY
D7	D7	Heater	80	24	65	5.0	1.8	18.0	6.6	Not Eligible, Red > 10 TPY
D8	D8	Heater	67	14	48	5.0	1.5	18.0	5.3	Not Eligible, Red > 10 TPY
D9	D9	Heater	108	12	22	5.0	2.7	18.0	9.6	Eligible
D10	D10	Boiler	330	11	10	5.0	5.5	7.5	8.3	Not Eligible
D11	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0	Eligible
D12	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0	Eligible
D13	D13	Heater	64	3	8	5.0	1.9	18.0	6.8	Eligible
D14	D14	Thermal Oxidizer	4	3	43	30.0	2.1	40.0	2.8	Not Eligible
D15	D15	Heater	17	3	12	9.0	2.3	N/A	N/A	No Table 2 Limit
D16	D16	Sulfur Recovery Unit	40	10	35	30.0	8.6	N/A	N/A	No Table 2 Limit
Baseline Facility Emissions				730						

245 tons/year - 12.3 tons/year = 232.8 tons/year
Not Eligible, 232.8 > 20 tons/year

As shown in Table 315 below, if Table 1 is selected the Facility BARCT Emission Target will be based on the emissions as if the unit met the Table 1 limits. Similarly, if Table 2 is selected, the Facility BARCT Emission Target will be based on the emissions as if the unit met Table 2 limits. If a unit is list in Table D-1 in Attachment D of PR 1109.1, the unit already meets the conditions for using Table 2 and the permit application would be submitted based on the schedule in the approved I-Plan as opposed to July 1, 2022 for units that will be meeting the provisions of subparagraphs (d)(2)(A) and (d)(2)(B). The table below notes those units as "Eligible."

The Final BARCT Emission Target is the sum of the emissions for the selected Table 1 or Table 2 NOx limits, calculated using the equation below and pursuant to section (B-2) of PR 1109.1. For this example, the Final BARCT Emission Target is 175.0 tons per year.

$$\text{Final Phase Facility BARCT Emission Target} = \sum_{i=1}^{N}\left(\frac{C_{\text{Table 1 or Table 2}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions}\right)_i$$

Where:

N	=	Number of included Units in B-Plan or B-Cap
$C_{\text{Table 1 or Table 2}}$	=	The applicable NOx Concentration Limit in Table 1 or Table 2 for each Unit i included in B-Plan or B-Cap
C_{Baseline}	=	Representative NOx Concentration as defined in subdivision (c) for Unit i included in B-Plan or B-Cap
Baseline Unit Emissions	=	Baseline Unit Emissions for Unit i as defined in subdivision (c) and included in the I-Plan, B-Plan or B-Cap as determined pursuant to section (B-1).

Besides three heaters (D11, D12 and D13) with Baseline Emissions below the PR 1109.1 Table 2 NOx emission limits, the owner identifies FCCU (D4), one heater (D9) and Thermal Oxidizer (D14) as potential devices to meet the requirements of PR 1109.1 Table 2 NOx limits. Therefore, the emissions of these units in the Final Phase Facility BARCT Emission Target in the final I-Plan is determined with respect to the reduction from these units to meet the applicable limits in PR 1109.1 Table 2.

Table 3-15. Calculating the Final BARCT Emission Target

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	PR 1109.1 Table 1 NOx Limit (ppmv)	PR 1109.1 Table 1 Remaining Emissions (Tons/Year)	PR 1109.1 Table 2 NOx Limit (ppmv)	PR 1109.1 Table 2 Remaining Emissions (Tons/Year)	Units Possibly Eligible for ... Conditions) — Initial Screening Based on Unit Reductions Only - Must Verify Other Conditions Met	Operator Selects Table 1 or Table 2 Limits (Table 2 Must Meet (d)(2))	NOx Lmit Based Selected Table 1 or Table 2 Limits (ppmv)
D1	D1	Heater	320	245	100	5.0	12.3	22.0	53.9	Not Eligible, Red > 20 TPY	Table 1	12.3
D2	D2	Boiler	210	126	38	5.0	16.6	7.5	24.9	Not Eligible, Red > 20 TPY	Table 1	16.6
D3	D3	SMR Heater	450	97	48	5.0	10.1	7.5	15.2	Not Eligible, Red > 20 TPY	Table 1	10.1
D4	D4	FCCU		83	11	2.0	15.1	8.0	60.4	Eligible	Table 2	60.4
D5	D5	Heater	290	54	18	5.0	15.0	22.0	66.0	Not Eligible	Table 1	15.0
D6	D6	Heater	135	29	33	5.0	4.4	22.0	19.3	Not Eligible, Red > 20 TPY	Table 1	4.4
D7	D7	Heater	80	24	65	5.0	1.8	18.0	6.6	Not Eligible, Red > 10 TPY	[illegible]	1.8
D8	D8	Heater	67	14	48	5.0	1.5	18.0	5.3	Not Eligible, Red > 10 TPY	[illegible]	1.5
D9	D9	Heater	108	12	22	5.0	2.7	18.0	9.6	Eligible	[illegible]	9.6
D10	D10	Boiler	330	11	10	5.0	5.5	7.5	8.3	Not Eligible	Table 1	5.5
D11	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0	Eligible	Table 2	9.0
D12	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0	Eligible	Table 2	9.0
D13	D13	Heater	64	3	8	5.0	1.9	18.0	6.8	Eligible	Table 2	6.8
D14	D14	Thermal Oxidizer	4	3	43	30.0	2.1	40.0	2.8	Not Eligible	Table 1	2.1
D15	D15	Heater	17	3	12	9.0	2.3	N/A	N/A	No Table 2 Limit	Table 1	2.3
D16	D16	Sulfur Recovery Unit	40	10	35	30.0	8.6	N/A	N/A	No Table 2 Limit	Table 1	8.6
Baseline Facility Emissions				**730**							Final Phase Facility BARCT Target	**175.0**

NOx emissions based on Table selection
Cannot select Table 2, if

Calculating the Total Facility NOx Emission Reductions for B-Plan

The Total Facility NOx Emission Reductions are the difference between the Baseline Facility Emissions and the Final Phase Facility BARCT Emission Target.

Total Facility NOx Emission Reductions must be calculated using the following equation, pursuant to section (B-3.1) of PR 1109.1:

$$\text{Total Facility NOx Emission Reductions} = \text{Baseline Facility Emissions} - \text{Final Phase Facility BARCT Emission Target}$$

Based on the calculated Baseline Emissions (section B-1) and Final Phase Facility BARCT Emission (section B-2) for this example, the Facility Total NOx Emission Reductions is equal to 555.0 tons/year (730 tons/year – 175.0 tons/year).

Table 3-16. Facility Total NOx Emission Reductions

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	PR 1109.1 Table 1 NOx Limit (ppmv)	PR 1109.1 Table 1 Remaining Emissions (Tons/Year)	PR 1109.1 Table 2 NOx Limit (ppmv)	PR 1109.1 Table 2 Remaining Emissions (Tons/Year)	Units Possibly Eligible for Conditional Limits Based on Potential Reductions (Refer to PR 1109.1 (d)(2) for all Conditions)	Operator Selects Table 1 or Table 2 Limits (Table 2 Must Meet (d)(2))	NOx Lmit Based Selected Table 1 or Table 2 Limits (ppmv)
D1	D1	Heater	320	245	100	5.0	12.3	22.0	53.9	Not Eligible, Red > 20 TPY	Table 1	12.3
D2	D2	Boiler	210	126	38	5.0	16.6	7.5	24.9	Not Eligible, Red > 20 TPY	Table 1	16.6
D3	D3	SMR Heater	450	97	48	5.0	10.1	7.5	15.2	Not Eligible, Red > 20 TPY	Table 1	10.1
D4	D4	FCCU		83	11	2.0	15.1	8.0	60.4	Eligible	Table 2	60.4
D5	D5	Heater	290	54	18	5.0	15.0	22.0	66.0	Not Eligible	Table 1	15.0
D6	D6	Heater	135	29	33	5.0	4.4	22.0	19.3	Not Eligible, Red > 20 TPY	Table 1	4.4
D7	D7	Heater	80	24	65	5.0	1.8	18.0	6.6	Not Eligible, Red > 10 TPY	Table 1	1.8
D8	D8	Heater	67	14	48	5.0	1.5	18.0	5.3	Not Eligible, Red > 10 TPY	Table 1	1.5
D9	D9	Heater	108	12	22	5.0	2.7	18.0	9.6	Eligible	Table 2	9.6
D10	D10	Boiler	330	11	10	5.0	5.5	7.5	8.3	Not Eligible	Table 1	5.5
D11	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0	Eligible	Table 2	9.0
D12	D11 and D12	Heater	75	8	16	5.0	2.5	18.0	9.0	Eligible	Table 2	9.0
D13	D13	Heater	64	3	8	5.0	1.9	18.0	6.8	Eligible	Table 2	6.8
D14	D14	Thermal Oxidizer	4	3	43	30.0	2.1	40.0	2.8	Not Eligible	Table 1	2.1
D15	D15	Heater	17	3	12	9.0	2.3	N/A	N/A	No Table 2 Limit	Table 1	2.3
D16	D16	Sulfur Recovery Unit	40	10	35	30.0	8.6	N/A	N/A	No Table 2 Limit	Table 1	8.6
Baseline Facility Emissions				730								175.0

Total Facility NOx Emission Reductions
730 tons/year - 175 tons/year = 555 tons/year

B-Plan

Calculating Phase I, Phase II, and Phase III Facility BARCT Emission Targets for an I-Plan with a B-Plan

The owner with a B-Plan calculates the expected level of NOx emissions at each phase of the selected I-Plan option using the following equations, pursuant to section (B-4) of PR 1109.1:

$$\text{Phase I Facility BARCT Emission Target}_{\text{B-Plan}} = \text{Baseline Emissions} - (\text{Each Phase Percent Reduction Target} \times \text{Total Facility NOx Emission Reductions})$$

For the final phase, the Phase Facility BARCT is the Final Phase Facility BARCT Target.

Here, if the owner chooses to proceed with an I-Plan Option 1, the calculations will be as follows:

$$\textbf{Phase I Facility BARCT Emission Target}_{\textbf{B-Plan}} = \mathbf{730 - (555 \times 0.7) = 341.5}\ \textbf{tons/year}$$

$$\textbf{Phase II Facility BARCT Emission Target}_{\textbf{B-Plan}} = \textbf{Final Phase Facility BARCT Emission Target} = \mathbf{175.0}\ \textbf{tons/year}$$

Calculating Phase I, Phase II, and if Applicable Phase III BARCT Equivalent Mass Emissions for a B-Plan

After the Phase I and II Facility BARCT Emission Targets are established, the operator then calculates the BARCT Equivalent Mass Emissions. For the B-Plan, the emissions are based on the concentration limits. Units that are decommissioned must be removed from the Baseline Facility Emissions and the Facility BARCT Emission Targets. As shown in the table below, the operator selects the Phase I Alternative BARCT Emission Limit for each unit. For the B-Plan, the Phase I

BARCT Equivalent Mass Emissions are the sum of the emissions for all units using the Alternative BARCT Emission Limits. In the example below, the Phase I BARCT Equivalent Emissions are 288.9 tons/year and the Phase II BARCT Equivalent Emissions are 173.8 tons/year.

Table 3-17. Calculating Phase I BARCT Equivalent Mass Emissions for B-Plan

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	Units Possibly Eligible for Conditional Limits Based on Potential Reductions (Refer to PR 1109.1 (d)(2) for all Conditions)	Operator Specifies if Unit will be Decommissioned (Yes/No)	Phase I Alternative BARCT Emission Limit (ppmv)	Phase I BARCT Equivalent Emissions (Tons/Year)	Phase II Alternative BARCT Emission Limit (ppmv)	Phase II BARCT Equivalent Emissions (Tons/Year)
D1	D1	Heater	320	245	100	Not Eligible, Red > 20 TPY	N/A	15.0	36.8	5.0	12.3
D2	D2	Boiler	210	126	38	Not Eligible, Red > 20	[illegible]	15.0	49.7	5.0	16.6
D3	D3	SMR Heater	450	97	48	Not Eligible, Red > 20	[illegible]	10.0	20.2	10.0	20.2
D4	D4	FCCU		83	11	Eligible	[illegible]	7.0	52.8	7.0	52.8
D5	D5	Heater	290	54	18	Not Eligible	[illegible]	6.0	18.0	6.0	18.0
D6	D6	Heater	135	29	33	Not Eligible, Red > 20 TPY	N/A	33.0	29.0	[illegible]	3.5
D7	D7	Heater	80	24	65	Not Eligible, Red > 10 TPY	N/A	65.0	24.0	[illegible]	3.3
D8	D8	Heater	67	14	48	Not Eligible, Red > 10 TPY	N/A	9.0	2.6	[illegible]	2.6
D9	D9	Heater	108	12	22	Eligible	N/A	18.0	9.6	[illegible]	9.6
D10	D10	Boiler	330	11	10	Not Eligible	N/A	10.0	11.0	[illegible]	3.8
D11	D11 and D12	Heater	75	8	16	Eligible	N/A	12.0	6.0	[illegible]	5.0
D12	D11 and D12	Heater	75	8	16	Eligible	N/A	20.0	10.0	[illegible]	0.0
D13	D13	Heater	64	3	8	Eligible	N/A	8.0	3.0	[illegible]	3.0
D14	D14	Thermal Oxidizer	4	3	43	Not Eligible	N/A	43.0	3.0	10.0	0.7
D15	D15	Heater	17	3	12	No Table 2 Limit	N/A	12.0	3.1	9.0	2.3
D16	D16	Sulfur Recovery Unit	40	10	35	No Table 2 Limit	N/A	35.0	10.0	14.0	4.0
Baseline Facility Emissions				**730**		Phase I BARCT Equivalent Emissions			**288.9**		**173.8**

Operator selects Alternative BARCT Emission Limit for Each Unit

Phase I BARCT Equivalent Emissions are the sum of the mass emission for each unit using the Alternative BARCT

For the B-Plan, the operator must calculate the BARCT Equivalent Mass Emissions for each phase of the I-Plan, using the equation in sections (B-6.1) and (B-6.2) of PR 1109.1. The Phase I and Phase II (if not the final phase) BARCT Equivalent Mass Emissions for the B-Plan equation is shown below. Final Phase BARCT Equivalent Mass Emissions (i.e., Phase II if it is the final phase and Phase III) are calculated with the same equation but using only the Alternative BARCT Emission Limits for the applicable phase (using Representative NOx Concentrations for Phase III is not allowed).

$$\text{Phase I and Phase II BARCT Equivalent Mass Emissions}_{\text{B-Plan}} = \sum_{i=1}^{N}\left(\frac{C_{\text{Phase I Alternative BARCT NOx Limit}}\ \boldsymbol{OR}\ C_{\text{Baseline}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions}\right)_i$$

Where:

N = Number of included units in B-Plan under Phase I

$C_{\text{Phase I Alternative BARCT Emission Limit}}$ = The applicable Alternative BARCT NOx Limit for Phase I in an approved B-Plan for unit i included in the B-Plan

C_{Baseline} = The NOx concentration in the flue gas for unit i included in the B-Plan

Baseline Unit Emissions = The 2017 NOx baseline emissions for unit i included in the B-Plan.

Demonstration that BARCT Equivalent Mass Emissions is Less than or Equal to Facility BARCT Emission Target for the B-Plan

For the B-Plan, the last step is to demonstrate for each phase that the BARCT Equivalent Mass Emissions are less than or equal to that Phase Facility BARCT Emission Target. As shown in the table below, the Phase I BARCT Equivalent Emissions are 288.9 tons/year which are less than the

Phase I Facility BARCT Emission Target of 341.5 tons/year; and the Phase II BARCT Equivalent Mass Emissions are 173.8 tons/year which are less than the Phase II Facility BARCT Emission Target of 175.0 tons/year. If the BARCT Equivalent Mass Emissions are greater than the Facility BARCT Emission Target, then the operator will need to lower the Alternative BARCT Emission Limits for all or part of the included units in the corresponding phase. For the B-Plan, the Facility BARCT Emission Targets are used only to demonstrate that the Alternative BARCT emission limits are in aggregate at or below the Facility BARCT Emission Target. Operators using an approved B-Plan are not required to adhere to a facility-wide emission cap but must implement the Alternative BARCT Emission Limits for each phase.

Table 3-18. Demonstrating the B-Plan Will Achieve the Facility BARCT Emission Targets

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	Units Possibly Eligible for Conditional Limits Based on Potential Reductions (Refer to PR 1109.1 (d)(2) for all Conditions)	Operator Specifies if Unit will be Decommissioned (Yes/No)	Phase I Alternative BARCT Emission Limit (ppmv)	Phase I BARCT Equivalent Emissions (Tons/Year)	Phase II Alternative BARCT Emission Limit (ppmv)	Phase II BARCT Equivalent Emissions (Tons/Year)
D1	D1	Heater	320	245	100	Not Eligible, Red > 20 TPY	N/A	15.0	36.8	5.0	12.3
D2	D2	Boiler	210	126	38	Not Eligible, Red > 20 TPY	N/A	15.0	49.7	5.0	16.6
D3	D3	SMR Heater	450	97	48	Not Eligible, Red > 20 TPY	N/A	10.0	20.2	10.0	20.2
D4	D4	FCCU		83	11	Eligible	N/A	7.0	52.8	7.0	52.8
D5	D5	Heater	290	54	18	Not Eligible	N/A	6.0	18.0	6.0	18.0
D6	D6	Heater	135	29	33	Not Eligible, Red > 20 TPY	N/A	33.0	29.0	4.0	3.5
D7	D7	Heater	80	24	65	Not Eligible, Red > 10 TPY	N/A	65.0	24.0	9.0	3.3
D8	D8	Heater	67	14	48	Not Eligible, Red > 10 TPY	N/A	9.0	2.6	9.0	2.6
D9	D9	Heater	108	12	22	Eligible	N/A	18.0	9.6	18.0	9.6
D10	D10	Boiler	330	11	10	Not Eligible	N/A	10.0	11.0	8.0	8.8
D11	D11 and D12	Heater	75	8	16	Eligible	N/A	12.0	6.0	12.0	6.0
D12	D11 and D12	Heater	75	8	16	Eligible	N/A	20.0	10.0	20.0	10.0
D13	D13	Heater	64	3	8	Eligible	N/A	8.0	3.0	[illegible]	3.0
D14	D14	Thermal Oxidizer	4	3	43	Not Eligible	N/A	43.0	3.0	[illegible]	0.7
D15	D15	Heater	17	3	12	No Table 2 Limit	N/A	12.0	3.1	[illegible]	2.3
D16	D16	Sulfur Recovery Unit	40	10	35	No Table 2 Limit	N/A	35.0	10.0	[illegible]	4.0
Baseline Facility Emissions				**730**				Phase I BARCT Equivalent Emissions	**288.9**	Phase II BARCT Equivalent	**173.8**
								Facility BARCT Emission Targets	**341.5**		**175.0**

B-Cap

Calculating the Total Facility NOx Emission Reductions for B-Cap

Table 3-19. Calculating Phase I BARCT Equivalent Mass Emissions for B-Cap

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	Units Possibly Eligible for Conditional Limits Based on Potential Reductions (Refer to PR 1109.1 (d)(2) for all [illegible]	Operator Selects Table 1 or Table 2 Limits (Table 2 Must Meet (d)(2))	NOx Lmit Based Selected Table 1 or Table 2 Limits (ppmv)	Emissions Based on Selected Table 1 or Table 2 Limits (Tons/Year)
D1	D1	Heater	320	245	100	Unit will be decommissioned	Table 1	5.0	**12.3**
D2	D2	Boiler	210	126	38	Not Eligible, Red > 20 TPY	Table 1	5.0	16.6
D3	D3	SMR Heater	450	97	48	Not Eligible, Red > 20 TPY	Table [illegible]	[illegible]	10.1
D4	D4	FCCU		83	11	Eligible	Table [illegible]	[illegible]	60.4
D5	D5	Heater	290	54	18	Not Eligible	Table [illegible]	[illegible]	15.0
D6	D6	Heater	135	29	33	Not Eligible, Red > 20 TPY	Table 1	5.0	4.4
D7	D7	Heater	80	24	65	Not Eligible, Red > 10 TPY	Table 1	5.0	1.8
D8	D8	Heater	67	14	48	Not Eligible, Red > 10 TPY	Table 1	5.0	1.5
D9	D9	Heater	108	12	22	Eligible	Table 2	18.0	9.8
D10	D10	Boiler	330	11	10	Not Eligible	Table 1	5.0	5.5
D11	D11 and D12	Heater	75	8	16	Eligible	Table 2	18.0	9.0
D12	D11 and D12	Heater	75	8	16	Eligible	Table 2	18.0	9.0
D13	D13	Heater	64	3	8	Eligible	Table 2	18.0	6.8
D14	D14	Thermal Oxidizer	4	3	43	Not Eligible	Table 1	30.0	2.1
D15	D15	Heater	17	3	12	No Table 2 Limit	Table 1	9.0	2.3
D16	D16	Sulfur Recovery Unit	40	10	35	No Table 2 Limit	Table 1	30.0	8.6
Baseline Facility Emissions				**730**					**175.0**

12.3 was added to the Target

The calculation approach for Total Facility NOx Emission Reductions in B-Cap is the same as the calculation approach for a B-Plan, but with an additional 10 percent. This is a 10 percent environmental benefit to meet U.S. EPA requirements for Economic Incentive Programs. Under this example for B-Cap, I-Plan Option 4 is used. If a unit is listed in Table D-2 in Attachment D of PR 1109.1, the unit already meets the conditions for using Table 2 and the permit application would be submitted based on the schedule in the approved I-Plan as opposed to June 1, 2022 for units that will be meeting the provisions of paragraphs (d)(3) and (f)(3). Under I-Plan Option 4, only units that are identified in Table D-2 are allowed to meet the Table 2 conditional limits in lieu of Table 1. These units meet all the conditions under subparagraph (d)(3) and have a representative NOx concentration at or below 25 ppmv.

Total Facility NOx Emission Reductions for B-Cap must be calculated using the following equation pursuant to section (B-3.2) of PR 1109.1:

$$\begin{aligned}\text{Total Facility NOx Emission Reductions}_{\text{B-Cap}}\\ &= \text{Baseline Facility Emissions}\\ &- (\text{Final Phase Facility BARCT Emission Target} \times 0.9)\end{aligned}$$

Based on the calculated Baseline Emissions (section B-1) and Final Phase Facility BARCT Emission (section B-2) for this example, the Facility Total NOx Emission Reductions is equal to 572.6 tons/year (730 tons/year – 175.0 tons/year × 0.9).

Calculating Phase I, Phase II, and Phase III BARCT Facility Emission Targets for an I-Plan with a B-Cap

The calculation for the Phase I, Phase II, and Phase III BARCT Facility Emission Targets is the same as the calculation approach for a B-Plan, except that the Facility BARCT Emission Target for each phase of I-Plan will be adjusted for any unit with an approved time extension. This adjustment is applied by adding the Baseline Unit Emissions in Phase I and the Unit BARCT B-Cap Annual Emissions from the previous phase in Phase II and Phase III for each Unit with an approved time extension to the corresponding phase Facility BARCT Emission Target based on the equation in sections (B4.4.1), (B-4.4.2) and (B-4.4.3) of PR 1109.1.

For I-Plan Option 4, the Phase I, Phase II and Phase III Facility BARCT Emission Target calculations will be as follows, using the equations in sections (B4.4.1), (B-4.4.2) and (B-4.4.3):

$$\textbf{Phase I Facility BARCT Emission Target}_{\textbf{B-Cap}} = \mathbf{730 - (572.6 \times 0.5) = 443.7} \textbf{ tons/year}$$

$$\textbf{Phase II Facility BARCT Emission Target}_{\textbf{B-Cap}} = \mathbf{730 - (572.6 \times 0.8) = 272.03} \textbf{ tons/year}$$

$$\textbf{Phase II Facility BARCT Emission Target}_{\textbf{B-Cap}} = \mathbf{730 - (572.6 \times 1.0) = 157.5} \textbf{ tons/year}$$

Calculating Phase I, Phase II, and if Applicable Phase III BARCT Equivalent Mass Emissions for a B-Cap

After the Facility BARCT Emission Targets for each phase are established, the operator then calculates the BARCT Equivalent Mass Emissions for each phase using the corresponding equations in sections (B-6.3) and (B-6.4) of PR 1109.1. As shown in the table below, the operator selects the Alternative BARCT Emission Limit or Representative NOx Concentrations for each unit and any decommissioned units in each phase. The BARCT Facility Emission Target must be based on Table 1 NOx limits for any decommissioned unit. The BARCT Equivalent Mass Emissions are based on the concentration limits and emission reductions from decommissioned units.

Table 3-20. Calculating Phase I BARCT Equivalent Mass Emissions for B-Cap

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	Units Possibly Eligible for Conditional Limits Based on Potential Reductions (Refer to PR 1109.1 (d)(2) for all	Operator Specifies if Unit will be Decommissioned (Yes/No)	Phase I Alternative BARCT Emission Limit (ppmv)	Phase I BARCT Equivalent Emissions (Tons/Year)	Phase I BARCT B-Cap Annual Emissions (Tons/year)	Phase II Alternative BARCT Emission Limit (ppmv)	Phase II BARCT Equivalent Emissions (Tons/Year)	Phase II BARCT B-Cap Annual Emissions (Tons/year)	Phase III Alternative BARCT Emission Limit (ppmv)	Phase III BARCT Equivalent Emissions (Tons/Year)	Phase III BARCT B-Cap Annual Emissions (Tons/year)
D1	D1	Heater	320	245	100	N[illegible] Unit will be decommissioned	Yes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
D2	D2	Boiler	210	126	38	Not Eligible, Red > 20 TPY	No	38.0	126.0	126.0	38.0	126.0	70.0	10.0	33.2	33.2
D3	D3	SMR Heater	450	97	48	Not Eligible, Red > 20 TPY	No	45.0	90.9	85.0	10.0	20.2	20.2	10.0	20.2	20.2
D4	D4	FCCU		83	11	Eligible	No	11.0	83.0	83.0	7.0	52.8	52.8	7.0	52.8	30.0
D5	D5	Heater	290	54	18	Not Eligible	No	18.0	54.0	50.0	6.0	18.0	18.0	6.0	18.0	18.0
D6	D6	Heater	135	29	33	Not Eligible, Red > 20 TPY	No	6.0	5.3	5.3	6.0	5.3	5.3	6.0	5.3	5.3
D7	D7	Heater	80	24	65	Not Eligible, Red > 10 TPY	No	65.0	24.0	24.0	65.0	24.0	24.0	4.0	1.5	1.5
D8	D8	Heater	67	14	48	Not Eligible, Red > 10 TPY	No	48.0	14.0	14.0	48.0	14.0	14.0	4.0	1.2	1.2
D9	D9	Heater	108	12	22	Eligible	No	22.0	12.0	12.0	18.0	9.8	9.8	18.0	9.8	9.8
D10	D10	Boiler	330	11	10	Not Eligible	No	10.0	11.0	11.0	10.0	11.0	11.0	8.0	8.8	8.8
D11	D11 and D12	Heater	75	8	16	Eligible	No	16.0	8.0	8.0	12.0	6.0	6.0	12.0	6.0	6.0
D12	D11 and D12	Heater	75	8	16	Eligible	No	16.0	8.0	8.0	20.0	10.0	10.0	20.0	10.0	10.0
D13	D13	Heater	64	3	8	Eligible	No	8.0	3.0	3.0	8.0	3.0	3.0	8.0	3.0	3.0
D14	D14	Thermal Oxidizer	4	3	43	Not Eligible	No	43.0	3.0	3.0	43.0	3.0	3.0	10.0	0.7	0.7
D15	D15	Heater	17	3	12	No Table 2 Limit	No	12.0	3.0	3.0	12.0	3.0	3.0	9.0	2.3	2.3
D16	D16	Sulfur Recovery Unit	40	10	35	No Table 2 Limit	No	14.0	4.0	4.0	35.0	10.0	10.0	14.0	4.0	4.0
Baseline Facility Emissions				**730**					**449.2**	**439.3**		**316.1**	**260.1**		**176.7**	**153.8**

Calculating Phase I, Phase II, and if Applicable Phase III BARCT B-Cap Annual Emissions

The owner or operator then must calculate the BARCT B-Cap Annual Emissions for each phase of the I-Plan, pursuant to equations in section (B-7) of PR 1109.1. For the B-Cap, the BARCT B-Cap Annual Emissions for each phase are the sum of the emissions for all units using the Alternative BARCT Emission Limits, accounting for any decommissioned units, and throughput or other emission reductions. In the example below, the Phase I BARCT Equivalent Emissions are 439.3 tons/year, the Phase II BARCT Equivalent Emissions are 260.1 tons/year and the Phase III BARCT Equivalent Emissions are 153.8 tons/year.

In the table above, green cells identify the units that contribute to the emissions reductions in each phase through implementation of emission reduction projects. Yellow cells are the units with emission reduction achieved only through replacing units, reducing throughput or other reductions. The orange cells specify the corresponding Unit BARCT B-Cap Annual Emissions for retrofitted or not retrofitted units based on reduction strategies which are different from the mass emission for that unit based on the Alternative NOx Concentration Limit. The operator is required by the rule to provide an explanation to the Executive Officer about these units for which the Unit BARCT B-Cap Annual Emissions are less than the BARCT Equivalent Mass Emissions.

The Phase I and Phase II (if not the final phase) BARCT B-Cap Annual Emissions for the B-Cap equation is shown below. Final Phase BARCT B-Cap Annual Emissions (i.e., Phase II if it is the final phase and Phase III) are calculated with the same equation, using only the Alternative BARCT Emission Limits for the applicable phase (using Representative NOx Concentrations for Phase III is not allowed) and additional emission reduction strategies to reduce mass emissions.

Phase I and Phase II BARCT B-Cap Annual Emissions

$$= \sum_{i=1}^{N} \left[\left(\frac{C_{\text{Phase I Alternative BARCT NOx Limit}} \boldsymbol{OR}\ C_{\text{Baseline}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions} \right)_i + (0_{\text{Decommissioned Units}})_i - (\text{Throughput or Other Reductions})_i \right]$$

Where:

N = Number of included units in B-Cap under Phase I

$C_{\text{Phase I Alternative BARCT Emission Limit}}$ = The applicable Alternative BARCT NOx Limit for Phase I in an approved B-Plan for unit i included in the B-Cap

C_{Baseline} = The NOx concentration in the flue gas for unit i included in the B-Cap

Baseline Unit Emissions = The 2017 NOx baseline emissions for unit i included in the B-Plan

Throughput or Other Reductions = Emission reductions other than reduc4ing the concentration limit.

In this example (Figure 3-20), unit D1 is decommissioned and the difference between the sum of units BARCT Equivalent Emissions and units BARCT B-Cap Annual Emissions in each phase is due to emission reductions from "throughput or any other emission reductions" applied to unit D5 in Phase I, D2 in Phase II and unit D4 in Phase III (highlighted in orange color).

Demonstration that BARCT B-Cap Annual Emissions is Less than or Equal to Facility BARCT Emission Target for the I-Plan and On-Going Demonstration

For the B-Cap, there are two demonstrations that are required. The first demonstration is that the Phase I, Phase II, and Phase III BARCT B-Cap Annual Emissions are less than or equal to the respective Phase I, Phase II, and Phase III Facility BARCT Emission Target. The operator is required to take permit conditions for each of the Alternative BARCT Limits in the approved B-Cap. Under the B-Cap, the second compliance demonstration is to continuously demonstrate that facility-wide emissions are below the Facility BARCT Emission Target for each phase. Staff believes that this two-pronged compliance demonstration is needed to ensure that there is a commitment to implement the Alternative BARCT Emission Limits while ensuring mass emissions are continuously below the Phase I, II, and III Facility BARCT Emission Targets.

As shown in the table below, the Phase I BARCT Equivalent Emissions are 439.3 tons/year which are less than the Phase I Facility BARCT Emission Target of 443.7 tons/year; the Phase II BARCT Equivalent Mass Emissions are 260.1 tons/year which are less than the Phase II Facility BARCT Emission Target of 272.0 tons/year; and the Phase III BARCT B-Cap Annual Emissions are 153.8 tons/year which are less than the Phase III Facility BARCT Emission Target of 157.5 tons/year. The operator must demonstrate on an ongoing basis that actual emission for all units in the B-Cap are below the Phase Facility BARCT Emission Targets.

Table 3-21. Demonstrating the B-Cap Will Achieve the Facility BARCT Emission Targets

Device ID	Combined Stack	Category	Size (MMBtu/hr)	Baseline Unit Emissions (Tons/Year)	Representative NOx (ppmv)	Units Possibly Eligible for Conditional Limits Based on Potential Reductions (Refer to PR 1109.1 (d)(2) for all	Operator Specifies if Unit will be Decommissioned (Yes/No)	Phase I Alternative BARCT Emission Limit (ppmv)	Phase I BARCT Equivalent Emissions (Tons/Year)	Phase I BARCT B-Cap Annual Emissions (Tons/year)	Phase II Alternative BARCT Emission Limit (ppmv)	Phase II BARCT Equivalent Emissions (Tons/Year)	Phase II BARCT B-Cap Annual Emissions (Tons/year)	Phase III Alternative BARCT Emission Limit (ppmv)	Phase III BARCT Equivalent Emissions (Tons/Year)	Phase III BARCT B-Cap Annual Emissions (Tons/year)
D1	D1	Heater	320	245	100	N[illegible]	Yes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
D2	D2	Boiler	210	126	38	Not Eligible, Red > 20 TPY	No	38.0	126.0	126.0	38.0	126.0	70.0	10.0	33.2	33.2
D3	D3	SMR Heater	450	97	48	Not Eligible, Red > 20 TPY	No	45.0	90.9	85.0	10.0	20.2	20.2	10.0	20.2	20.2
D4	D4	FCCU		83	11	Eligib[illegible]	[illegible]	[illegible]	83.0	83.0	7.0	52.8	52.8	7.0	52.8	30.0
D5	D5	Heater	290	54	18	Not Elig[illegible]	[illegible]	18.0	54.0	50.0	6.0	18.0	18.0	6.0	18.0	18.0
D6	D6	Heater	135	29	33	Not Eligible, Re[illegible]	[illegible]	6.0	5.3	5.3	6.0	5.3	5.3	[illegible]	[illegible]	5.3
D7	D7	Heater	80	24	65	Not Eligible, Re[illegible]	[illegible]	65.0	24.0	24.0	65.0	24.0	24.0	4.0	[illegible]	1.5
D8	D8	Heater	67	14	48	Not Eligible, Re[illegible]	[illegible]	48.0	14.0	14.0	48.0	14.0	14.0	4.0	[illegible]	1.2
D9	D9	Heater	108	12	22	Eligib[illegible]	[illegible]	22.0	12.0	12.0	18.0	9.8	9.8	18.0	[illegible]	9.8
D10	D10	Boiler	330	11	10	Not Eligible	No	10.0	11.0	11.0	10.0	11.0	11.0	8.0	8.8	8.8
D11	D11 and D12	Heater	75	8	16	Eligible	No	16.0	8.0	8.0	12.0	6.0	6.0	12.0	6.0	6.0
D12	D11 and D12	Heater	75	8	16	Eligible	No	16.0	8.0	8.0	20.0	10.0	10.0	20.0	10.0	10.0
D13	D13	Heater	64	3	8	Eligible	No	8.0	3.0	3.0	8.0	3.0	3.0	8.0	3.0	3.0
D14	D14	Thermal Oxidizer	4	3	43	Not Eligible	No	43.0	3.0	3.0	43.0	3.0	3.0	10.0	0.7	0.7
D15	D15	Heater	17	3	12	No Table 2 Limit	No	12.0	3.0	3.0	12.0	3.0	3.0	9.0	2.3	2.3
D16	D16	Sulfur Recovery Unit	40	10	35	No Table 2 Limit	No	14.0	4.0	4.0	35.0	10.0	10.0	14.0	4.0	4.0
Baseline Facility Emissions				**730**					**449.2**	**439.3**		**316.1**	**260.1**		**176.7**	**153.8**
									Facility BARCT Emission Targets	**443.7**			**272.0**			**157.5**

Unit will be decommissioned

Permit to Construct was issued **3 months** after 18 months from the date the complete permit application submittal

Executive Officer approved a **12-month** time extenion for this Unit

On-Going Demonstration that Actual Emissions ≤ Facility BARCT Emission Target

Revised @ 54 months from permit application submittal	**455.7**	Late permit for D3 in Phase I
Revised @ 54+3 months from permit application submittal	**443.7**	Permit issued for D3/Construction is done
Revised @ 54 months from permit application submittal	**304.0**	Time extension approved for D5 in Phase II
Revised @ 54+12 months from permit application submittal	**272.0**	Permit issued for D5/Construction is done

Pursuant to paragraph (j)(10) of PR 1109.1, if an owner or operator receives an approval for a time extension, the Facility BARCT Emission Target will be adjusted for the corresponding phase of selected I-Plan. In this example, Permit to Construct was not issued within 18 months since the complete permit application submittal for units D3 and time extension was approved for Unit D5 (highlighted in pink color). Therefore, the Facility BARCT Emission Target is adjusted for the corresponding phase of I-Plan. Here, the owner or operator submitted the permit application for Unit D3, but the Permit to Construct was issued for this unit with 3 months delay. Therefore, the Facility BARCT Emission Target for Phase I is adjusted by the "Baseline Unit Emission" value of 97 tpy (highlighted in light blue color), using the equation for Phase I Facility BARCT Emission Target for B-Cap (refer to PR 1109.1 Section (B-4.4.1)). The Phase I Facility BARCT Emission Target is adjusted again after 3 months by reducing the "Baseline Unit Emission" value for D3. In Phase II, Unit D5 was approved by the Executive Officer for a 12-month time extension and the Facility BARCT Emission Target for Phase II is adjusted by the Unit BARCT B-Cap Annual Emissions for Unit D5 in the previous phase (50 tpy in Phase I) using the equation for Phase II Facility BARCT Emission Target for B-Cap (refer to PR 1109.1 Section (B-4.4.2)). The Phase II Facility BARCT Emission Target is adjusted again after 12 months by reducing the "Unit BARCT B-Cap Annual Emissions in Phase I" for D5.

PR 1109.1 ATTACHMENT C – FACILITIES EMISSIONS – BASELINE AND TARGETS

Attachment C contains Baseline Facility Emissions as reported by the facilities with six or more units in their 2017 Annual Emissions Reports, or another year, as approved by the Executive Officer. PR 1109.1 Table C-1, presented in the table below, provides the Baseline Facility Emissions for the corresponding facilities subject to PR 1109.1.

Table 3-22. PR 1109.1 Table C-1 – Baseline Mass Emissions for Facilities with Six or More Units

Facility	Facility ID	Baseline Facility Emissions (2017 or Representative Year) (tons/year)
AltAir Paramount, LLC	187165	~~28~~<u>24</u>
Chevron Products Co.	800030	~~701~~<u>705</u>
Lunday-Thagard Co. DBA World Oil Refining	800080	26
Phillips 66 Company/Los Angeles Refinery	171109	~~386~~<u>387</u>
Phillips 66 Co/LA Refinery Wilmington PL	171107	~~462~~<u>456</u>
Tesoro Refining and Marketing Co., LLC – Carson	174655	~~613~~<u>639</u>
Tesoro Refining and Marketing Co., LLC – Wilmington	800436	~~594~~<u>597</u>
Tesoro Refining and Marketing Co., LLC – Sulfur Recovery Plant	151798	~~35~~<u>43</u>
Tesoro Refining and Marketing Co., LLC, Calciner	174591	261
Torrance Refining Company LLC	181667	~~898~~<u>737</u>
Ultramar Inc.	800026	~~248~~<u>249</u>
Valero Wilmington Asphalt Plant	800393	~~5~~<u>4.8</u>

PR 1109.1 ATTACHMENT D – UNITS QUALIFY FOR CONDITIONAL LIMITS IN B-PLAN AND B-CAP

Table 3-23. PR 1109.1 Table D-1 – Process Heaters and Boilers >40 MMBtu/hr That Qualify for Conditional Limits in B-Plan or B-Cap using I-Plan Option 3

Facility ID	Device ID	Size (MMBtu/hr)
171109	D429	352
171109	D78	154
~~**174655**~~	~~D1465~~	~~427~~
174655	D419	52
174655	D532	255
174655	D63	300
181667	D1236	340
181667	D1239	340
181667	D231	60
181667	D232	60
181667	D234	60
181667	D235	60
181667	D950	64
800026	D1550	245
800026	D6	136
800026	D768	110
800030	D643	220
800030	D82	315
800030	D83	315
800030	D84	219
800030	D466	62
800030	D467	62
800436	D1122	140
800436	D384	48
800436	D385	24
800436	D388	147
800436	D770	63
~~**800436**~~	~~D777~~	~~146~~

Table 3-24. PR 1109.1 Table D-2 – Units That Qualify for Conditional Limits in ~~B-Plan or~~ B-Cap using I-Plan Option 4

Facility ID	Device ID	Size (MMBtu/hr)
171107	D220	350
171107	D686	304
171109	D429	352
171109	D78	154
171109	D79	154
174655	C2979	4
174655	D1465	427
174655	D250	89
174655	D33	100
174655	D419	52
174655	D421	82
174655	D532	255
174655	D539	52
174655	D570	650
174655	D63	360
181667	C686	4
181667	C687	4
181667	D1236	340
181667	D1239	340
181667	D231	60
181667	D232	60
181667	D234	60
181667	D235	60
181667	D920	108
181667	D950	64
800026	D1550	245
800026	D1669	342
800026	D378	128
800026	D429	30
800026	D430	200
800026	D53	68
800026	D6	136
800026	D768	110
800026	D98	57
800030	D453	44
800030	D643	220
800030	D82	315
800030	D83	315
800030	D84	219
800030	D466	62
800030	D467	62
800030	D203	-
800436	D1122	140
~~**800436**~~	~~D158~~	~~204~~
800436	D214	56

Facility ID	Device ID	Size (MMBtu/hr)
800436	D215	36
800436	D216	31
800436	D217	31
800436	D33	252
800436	D384	48
800436	D385	24
800436	D386	48
800436	D387	71
800436	D388	147
800436	D770	63
800436	D777	146

CHAPTER 4 IMPACT ASSESSMENT

INTRODUCTION

There are 16 facilities with a total of 284 units that will be subject to the PR 1109.1 which are all currently regulated under the RECLAIM program. PR 1109.1 will achieve emission reductions for every class and category of refinery equipment.

RULE DEVELOPMENT SUPPORTING MATERIALS AND SOURCES

Rule Development and Data Surveys

Staff conducted several surveys to develop a comprehensive understanding of the equipment at petroleum refineries and related industries, and their operational record. The following data surveys were requested and collected from each of the sixteen facilities impacted by PR 1109.1:

- Facility Based Equipment Data Survey
- Control Equipment Project Costs Data Survey
- CEMS Data Survey
- Fuel Gas Sulfur Content Data Survey
- Revised Control Equipment Project Cost Data Survey

Facility Based Equipment Data Survey

After holding several working group meetings to establish the universe of facilities and equipment that would be subject to PR 1109.1, staff developed a survey questionnaire to gather pertinent detailed information for the rule development. The intent of the data survey was to assist South Coast AQMD staff in developing PR 1109.1 and conducting the BARCT assessment to establish the NOx and CO limits. The survey was sent to all 16 facilities on May 24, 2018. The survey requested detailed information and data for all NOx sources affected by the proposed rule at each facility. The survey development was a collaborative process with the stakeholders and took several months to agree to the specific information being requested. Due to the level of detailed data requested, the facilities were provided approximately six months to submit the data. The facilities reported nearly 125 data points for each piece of equipment, including five years of annual fuel data, five years of annual emissions data, current and planned NOx controls, installation costs for planned controls, number of burners per unit, age of equipment, etc. In total, some facilities reported almost 3,000 data points and staff evaluated over 40,000 data points.

Control Equipment Project Costs Data Survey

The second survey was distributed to stakeholders prior to conducting site visits. As part of the rule development, staff conducted at least one site visit to each of the affected facilities from April through August 2019. This survey focused on the potential control technology, total installation cost, and operating and maintenance (O&M) costs. Staff requested a detailed cost breakdown for each project, but the level of detail varied depending on the stage of the project, such as the design and engineering phase, permitting, or already completed. Data from projects in early development stage was less detailed and more preliminary than projects in later stages of development.

In March 2021, four facilities provided updated revised cost data for potential control projects for 108 units in total, including new SCRs and SCR upgrades, low NOx burners, wet gas scrubbers, and unit replacement. Staff used the first cost survey data for facilities that did not provide updated costs in the second submission. While the facility’s focus in providing updated cost was on boilers and process heaters greater than or equal to 40 MMBtu/hr, which included 91 data points, some facilities provided updated costs for other categories including FCCU, Gas Turbine, SMR Heater, SRU/TG Incinerator, and Vapor Incinerator with a total of 17 data points as it is shown in the table below.

Table 4-1. Number of Units with Facility Provided Cost Data by Equipment Category and Facility

	Heaters	Boilers	SMR Heaters	FCCU	Gas Turbine	SRU/TG Incinerator	Vapor Incinerator
Facility #1	36	6	-	-	-	-	-
Facility #2	6	-	-	-	6	-	-
Facility #3	15	2	-	1	-	1	-
Facility #4	22	4	2	3	-	1	3

The new costs were also used to revise the U.S. EPA's SCR cost model that was used to estimate SCR project costs for units that cost was not provided by facilities. While only four out of the five petroleum refineries provided updated costs, the cost estimates for all five petroleum refineries increased as staff used the revised cost data provided by the facilities to update the U.S. EPA SCR cost model resulting in higher costs estimates for all SCR projects. As the box plot shows below, compared to the first cost survey, the updated revised cost increased significantly for all facilities. The plot shows the minimum, maximum, first and third quartiles, the median and the average values for each facility.

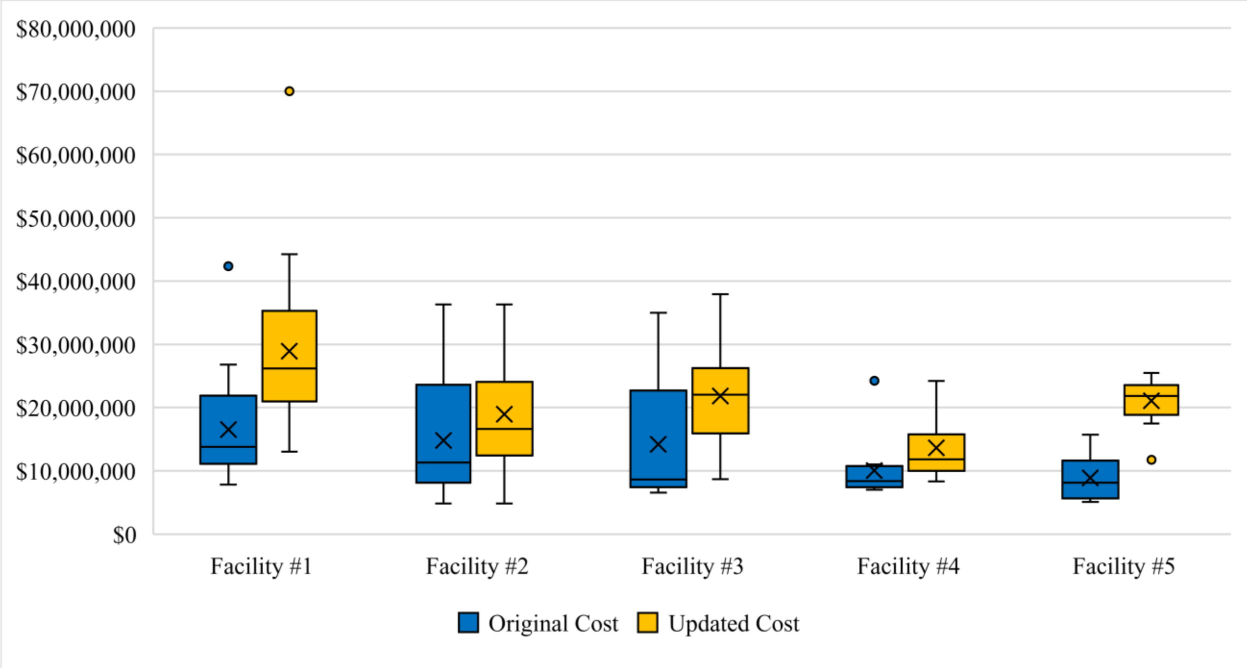


Figure 12. Original and updated cost provided by facilities

The following figure shows the number of units and range of control equipment costs that each facility provided in the second survey. Some facilities provided revisions to existing and new costs and for units. The control cost for Facility #1 was higher compared to the other facilities.

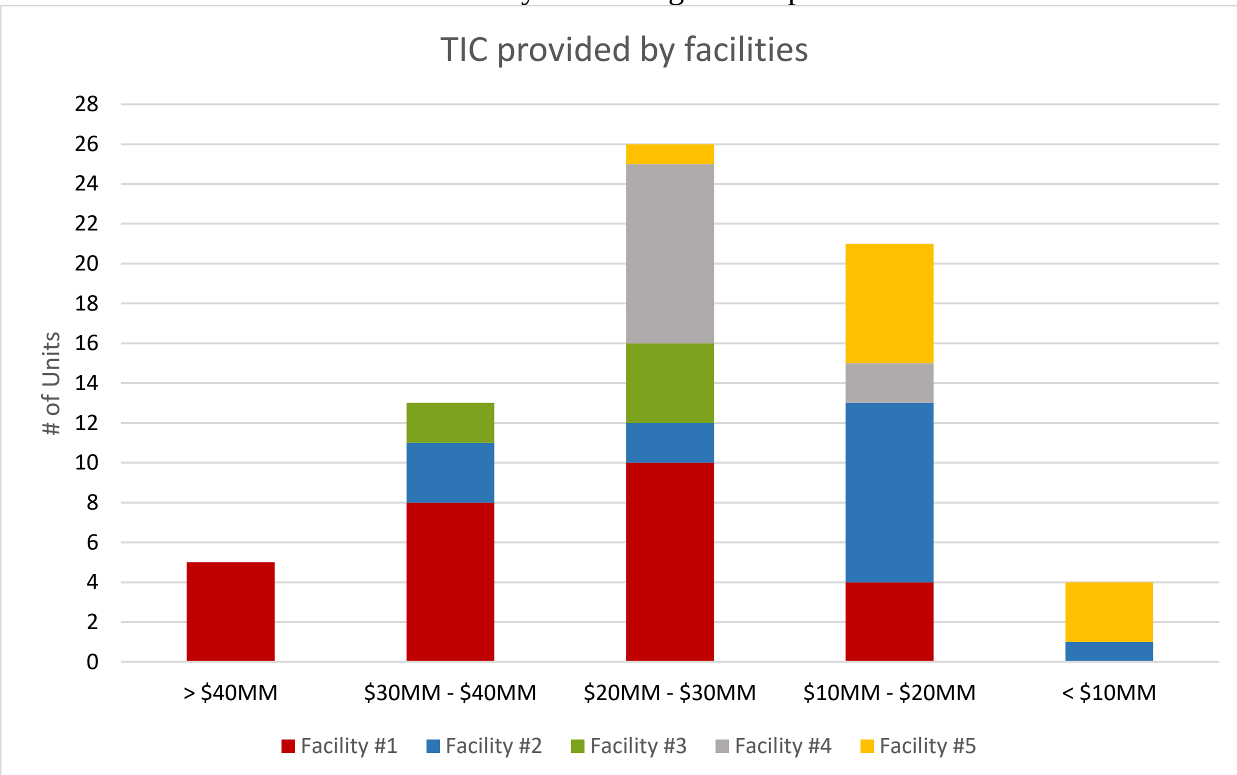


Figure 13. The number and range of control costs for each facility in the second survey

CEMS Data Survey

The CEMS survey was the third survey requested by staff from the facilities in March 2019. The CEMS data was requested for most large units (greater than 40 MMBtu/hr) as well as FCCU, coke calciner, and gas turbines. The CEMS provided staff with hourly data throughout an entire year which equated to 8,760 data points for every single unit. In addition, the CEMS data was needed to establish baseline emissions data and provided NOx concentrations, measured oxygen, flue gas stack flow rate, and fuel usage throughout the course of an entire year and amounted to nearly over 35,000 data points for a single unit. Some facilities have over 55 units, so nearly 2 million data points were provided for a single facility. Staff conducted an analysis for every single unit and every facility which gave staff insight into a unit's actual performance and operational variability.

Fuel Gas Sulfur Content Data Survey

The fuel gas sulfur survey was the fourth survey requested by staff from the facilities in March 2020. This survey was limited to the large petroleum refineries since fuel gas sulfur mainly impacts facilities utilizing refinery fuel gas, which typically has sulfur content. Refinery fuel gas streams, especially from coker units, contain sulfur compounds such as mercaptans and sulfides that are not effectively treated by the existing facilities' sulfur clean-up systems (e.g., amine systems). The sulfur in refinery fuel gas is converted to SOx and oxidized and converted to PM in the SCR due to the presence of ammonia. Staff requested this information in response to concerns regarding the high cost for meeting BACT requirements if PM emissions from the installation of SCR exceed the PM_{10} NSR thresholds. This survey provided staff detailed data on fuel gas streams, flow rate, affected units , sulfur content, existing treatment systems, and upgrade costs. The data was analyzed by staff to estimate the potential increase in PM emissions from SCR installations. As described in Chapter 1, staff collaborated with CARB and U.S. EPA to include a BACT exemption for non-ozone precursor emission increases associated with air pollution control equipment installations to comply with BARCT NOx standards. Staff will address refinery fuel sulfur content during the transition of SOx RECLAIM.

EMISSION INVENTORY AND EMISSION REDUCTIONS

The original NOx emission inventory for Petroleum Refineries was 12.4 tons per day based on a 2017 baseline. After the adoption of PR1109.1, the emissions are estimated to be reduced between 7.7 to 7.9 tons of NOx per day in accordance with the proposed implementation schedule. The table below summarizes the 2017 baseline emissions for all categories and the potential emission reductions.

Table 4-2. NOx Emission Inventory and Estimated Emission Reductions

Equipment Type	2017 NOx Baseline Emissions (tpd)	Potential NOx Emission Reductions (tpd)
Process Heaters	5.1	3.1-3.3
Boilers	2.6	2.2
Gas Turbine	1.4	0.4
SMR Heaters	1.1	0.6
FCCU	0.83	0.4
Coke Calciner	0.71	0.68
SRU/TG Incinerator	0.43	0.1
Sulfuric Acid Plants	0.1	0.0
Vapor Incinerators	0.05	0.02
10 percent Environmental Benefit	-	0.2
Total	12.4	7.7-7.9

COST-EFFECTIVENESS

California Health and Safety Code Section 40920.6 requires a cost-effectiveness analysis when establishing BARCT requirements. The cost-effectiveness of a control technology is measured in terms of the control cost in dollars per ton of air pollutant reduced is measured in terms of the control cost in dollars per ton of air pollutant reduced for each class and category of equipment. The costs for the control technology include purchasing, installation, operating, and maintaining the control technology.

The South Coast AQMD typically relies on the Discounted Cash Flow (DCF) method which converts all costs, including initial capital investments and costs expected in the present and all future years of equipment life, to a present value. Conceptually, it is as if calculating the amount of funds that would be needed at the beginning of the initial year to finance the initial capital investments but also funds to be set aside to pay off the annual costs as they occur in the future. The fund that is set aside is assumed to be invested and generates a rate of return at the discount rate chosen. The final cost-effectiveness measure is derived by dividing the present value of total costs by the total emissions reduced over the equipment life. DCF is calculated as follows:

$$Cost - effectiveness = \frac{Initial\ Capital\ Investments\ +\ (Annual\ O\&M\ Costs\ \times\ PVF)}{Annual\ Emission\ Reductions\ \times\ Years\ of\ Equipment\ Life}$$

Where:

$$PVF = \frac{(1+r)^N - 1}{r * (1+r)^{(N-1)}}$$

Where

r = real interest rate (discount rate); and
N = years of equipment life.

The present-value factor (PVF) converts a constant stream of payments made for N years into its single present-value equivalent.

Staff will also present Levelized Cash Flow (LCF) method which annualizes the present value of total costs as if all costs, including the initial capital investments, would be paid off in the future with an equal annual installment over the equipment life. LCF is

$$LCF = \left(\frac{Annualized\ Present\ Value\ of\ Total\ Costs}{Average\ Annual\ Emission\ Reductions}\right)$$

In general, DCF cost-effectiveness estimates are lower given the same interest rate and equipment life. The current DCF threshold was established in 2010 SOx RECLAIM BARCT assessment as $50,000 per ton reduced. If the threshold is inflated to represent current dollars using the Marshall and Swift Index the current values for DCF threshold would be approximately $60,000. A LCF threshold has not been established.

Control Equipment Cost Estimates

Staff relied on several sources of data to estimate the capital and installation costs and O&M costs of the control technology including the cost assumptions collected during the development of the 2015 RECLAIM NOx “shave”, costs from other BARCT NOx rules for similar equipment, vendor supplied cost estimates, SCR installations, and values calculated from the U.S. EPA SCR Spreadsheet. The stakeholders indicated staff’s estimates were an underestimation mainly due to the high-installation cost at refineries needed to address space constraints and the high labor costs driven by Senate Bill 54 (SB 54) which requires California refineries to hire unionized and trained construction labor for projects. As described in Chapter 1, staff conducted a survey of the affected facilities seeking total install and O&M for past or recent NOx reduction projects. Staff used the facility supplied cost data when it was provided. If no cost data was available, staff used the facility cost data to generate cost curves to estimate the cost. In the case of SCR costs, staff used the cost data provided by the facilities to update the U.S. EPA Cost Spreadsheet to estimate SCR costs. When both burner control and SCR were anticipated to be required to achieve the proposed NOx limits, the burner costs from the burner cost curve were added to the costs generated from the modified U.S. EPA Cost Spreadsheet. Staff’s cost assessment also included additional costs recommended by Norton Engineering and FERCo to address annual SCR tuning and increased catalyst volume. Detailed cost information can be found in the Appendices B-G for each category of equipment. The following is a summary of the cost assumptions for boilers and heaters:

- Initial ULNB cost based on vendor supplied estimates, staff adjusted costs as follows:
    - ✓ Conducted a survey seeking burner installation costs from facilities
    - ✓ Generated a curve based on the cost estimates provided by the facilities
    - ✓ Used facility cost when provided; otherwise, the burner curve was used to estimate cost

- Initial SCR costs based on U.S. EPA SCR Cost Spreadsheet; staff altered costs as follows:
  - ✓ Conducted a survey seeking SCR installation costs from facilities
  - ✓ Modified U.S. EPA SCR Spreadsheet using costs provided by the refineries to reflect costs at California refineries
  - ✓ Used stakeholder costs when provided, otherwise used modified U.S. EPA spreadsheet
- Units requiring greater than 92% NOx reductions:
  - ✓ Added cost of ULNB to the cost of SCR
  - ✓ Alternatively, conducted cost assessment for installation of dual reactors with 25% increase to TIC to address additional costs
- Based on feedback from third party engineering consultants:
  - ✓ Added $40,000 annual costs for SCR tuning – *based on FERCo recommendation*
  - ✓ Added 30% increased cost for the catalyst - *based on Norton Engineering recommendation to account for gas velocity*
- Estimated cost per unit project to achieve proposed NOx limits ranged from ~ $10 to $80 million (present worth value)

Estimated NOx Emission Reductions

Staff used 2017 annual NOx emissions as the baseline year since the PR 1109.1 development began in 2018; therefore, 2017 emissions was latest available annual set of data. For units where the 2017 emissions are not representative of the facilities operation, e.g., a unit was in turnaround or underutilized in 2017, staff used a more representative year reflecting more normal operations. Staff utilized the NOx concentration in the flue gas corrected to the appropriate percent oxygen (boilers, heaters, flares, and coke calciner corrected to three percent oxygen on a dry bases and gas turbines and SMR heaters combined with a gas turbine corrected to 15 percent oxygen on a dry basis) as provided by the facilities. Emission reductions are calculated based on the percent reduction from the current NOx concentration in the flue gas to the proposed NOx limit applied to the 2017 emissions data for each unit. Staff estimates that implementation of PR 1109.1 will achieve between 7.7 to 7.9 tons per day of NOx. The lower range represents the maximum number of units that can potentially use the conditional NOx limits under Table 2 and the upper range represents the units that staff identified that potentially meet the conditional NOx limits under Table 2 that were assumed in the cost-effectiveness analysis. Full implementation is expected around 2034. Some smaller units may extend beyond 2034 as they are required to meet the proposed NOx limit when more than 50 percent of unit’s burners are replaced.

Summary of Cost-Effectiveness by Class and Category

The following table is a summary of the cost-effectiveness for each class and category of equipment at the affect ted facilities, and the detailed analysis can be found in Appendices B-G.

Table 4-3. Summary of Cost-Effectiveness Using DCF and LCF

Equipment Category	Cost Effectiveness	
	DCF	LCF
Boilers (<20 MMBtu/hour)	-[(1)]	-[(1)]
Boilers (≥20 - <40 MMBtu/hour)	-[(1)]	-[(1)]
Boilers (≥40 - ≤110 MMBtu/hour)	$25,000	$37,000
Boilers (>110 MMBtu/hour)	$11,000	$19,000
Flares	-[(2)]	-[(2)]
FCCUs	$24,000	$65,000
FCCU Startup Heaters	-[(2)]	-[(2)]
Gas Turbines	$15,400	$42,000
Petroleum Coke Calciners	$10,000	$15,000
Process Heaters (<20 MMBtu/hour)	-[(1)]	-[(1)]
Process Heaters (≥20 - <40 MMBtu/hour)	-[(1)]	-[(1)]
Process Heaters (≥40 - ≤110 MMBtu/hour)	$50,500	$78,000
Process Heaters (>110 MMBtu/hour)	$50,000	$79,000
Sulfur Recovery Units/Tail Gas Treating Units	$39,000	$62,000
SMR Heaters	$17,000	$19,000
SMR Heaters with Gas Turbine	-[(1)]	-[(1)]
Sulfuric Acid Furnaces	-[(1)]	-[(1)]
Sulfuric Acid Startup Heater	-[(2)]	-[(2)]
Sulfuric Acid Startup Boiler	-[(2)]	-[(2)]
Vapor Incinerators	$35,000	$56,000

[(1)] Units will be required to retrofit burner control to meet future BARCT limit for category at end-of-useful life. Majority of cost will already be incurred by facility upon burner replacement

(2) Units will have a low use exemption and will not be required to install NOx control due to high cost-effectiveness and low emission reductions.

Conditional BARCT NOx Limits

As discussed in Chapter 2, staff identified several classes and categories of equipment that will have conditional limits in PR 1109.1. The table below provides an overview of cost effectiveness value to meet the Table 1 NOx limits and to meet the proposed conditional limits.

Table 4-4. Cost-effectiveness of Conditional Limits

Equipment Category	Table 1 NOx Limit (ppmv)	Proposed Conditional Limit (ppmv)	Cost Effectiveness ($/ton)	
			To Meet Table 1 NOx Limit	To Meet Conditional Limit
Boilers (>110 MMBtu/hr)	5	7.5	$75,000 -$8 Million	$0
FCCUs	2	8	$127,000	$12,000
Gas Turbines w/Natural Gas	2	2.5	$570,000	$0
Process Heaters (≥40 - ≤110 MMBtu/hour)	5	18	$53,000	$48,000
Process Heaters (>110 MMBtu/hour)	5	22	$56,000	$50,000
SMR Heaters	5	7.5	$242,000	$0
Vapor Incinerators	30	40	$100,000 - $500,000	$0

In order to ensure the conditional limit is utilized for those units with existing controls performing near the Table 1 NOx limits and it would not be cost effective to meet the Table 1 NOx limits, the proposed rule outlines conditions for using Table 2 conditional NOx limits. For example, the conditional limit is required to be in the permit by a certain date with any application to make minor modifications to be submitted by a certain date and cannot be a unit whose projected emission reductions are high. For more detailed discussion and analysis of the conditional limits can be found in the appendices of this staff report for each of the affected classes.

INCREMENTAL COST-EFFECTIVENESS

Health and Safety Code Section 40920.6 requires an incremental cost-effectiveness analysis for BARCT rules or emission reduction strategies when there is more than one control option which would achieve the emission reduction objective of the proposed amendments relative to ozone, carbon monoxide, sulfur oxides, oxides of nitrogen, and their precursors. Incremental cost-effectiveness is the difference in the dollar costs divided by the difference in the emission reduction potentials between each progressively more stringent potential control option as compared to the next less expensive control option. An incremental cost-effectiveness analysis has been conducted in concert with the BARCT analysis for each class and category. The figure below shows an overview of the California Health and Safety Code Section BARCT requirements.

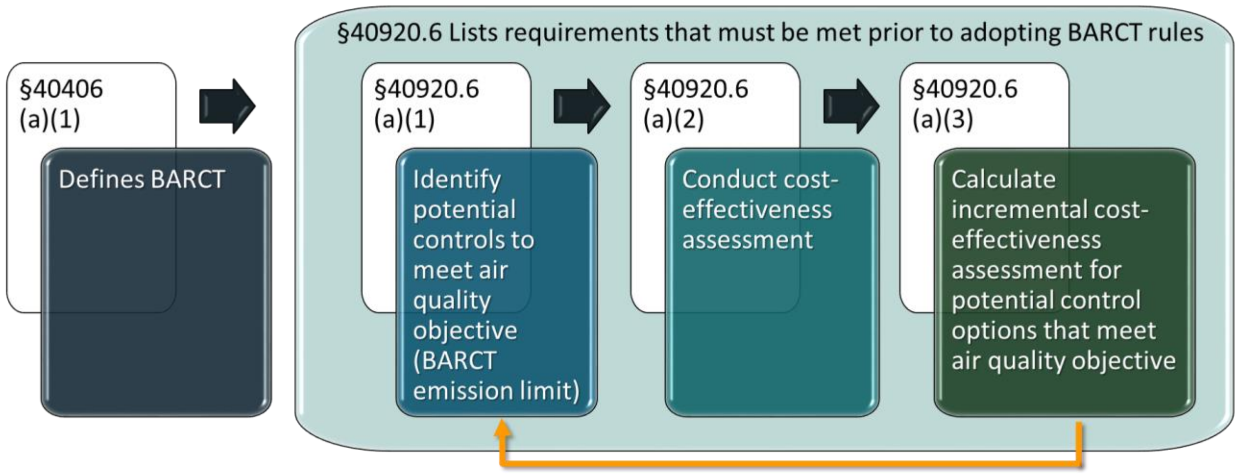


Figure 14. California Health and Safety Code Section BARCT Requirements

Step 1: Identify Control Options

In the first step, staff identifies one or more potential control options which achieves the emission reduction objectives for the regulation. For PR 1109.1, the "emission reduction objectives" is to establish a NOx emission limit representative of BARCT and by definition of BARCT staff is seeking the "maximum degree of reduction achievable by each class or category of source, considering the environmental, energy, and economic impacts."

Step 2: Determine Cost-Effectiveness

Staff calculates the cost-effectiveness, which is the cost in dollars, of the potential control option divided by emission reduction potential, in tons, of the potential control option.

$$Cost - Effectiveness = \frac{Cost}{Emission\ Reductions}$$

If the potential control option that will provide the maximum degree of reduction achievable is $50,000 per ton of NOx reduced or less, the next most stringent option may be selected as the potential control option, based on the 2016 AQMP cost-effectiveness threshold. If the most stringent potential control option is not cost-effective, staff calculates the cost-effectiveness of the next potential control option that will provide the maximum degree of reductions achievable.

Step 3: Calculate Incremental Cost-Effectiveness

Incremental cost-effectiveness is the difference in the dollar costs divided by the difference in the emission reduction potentials between each progressively more stringent potential control option as compared to the next less expensive control option.

$$Incremental\ Cost - Effectiveness = \frac{Cost_A - Cost_B}{Emission\ Reductions_A - Emission\ Reductions_B}$$

This step requires that the incremental cost-effectiveness be calculated for all potential control options identified in Step 1, even if the cost-effectiveness was not evaluated in Step 2. Evaluation of the incremental cost-effectiveness can identify a different NOx limit than Step 2 if the difference in reductions is small relative to the difference in cost between potential control options. If the incremental cost-effectiveness reveals that a more stringent control option has a high incremental cost-effectiveness, a less stringent NOx limit will be assessed and can be determined to be BARCT.

Although there is no threshold for evaluating incremental cost-effectiveness, staff agrees that a lower NOx limit with an incremental cost-effectiveness well above $50,000 per ton of NOx reduced is an indication that the more stringent control option is not incrementally cost-effective. The detailed incremental cost-effectiveness analysis for each class and category is presented in Appendices B – G.

BARCT EQUIVALENT COMPLIANCE PLANS

PR1109.1 seeks to maximize NOx emission reductions by imposing stringent NOx limits during the operation of refinery equipment resulting in 7-8 tons per day NOx reductions. These reductions are crucial in meeting the ambient air quality standards for ozone and PM since NOx is a major constituent of ozone and precursor to PM. By meeting the standards, the public health of the region will improve as premature deaths are avoided, asthma cases are avoided, and number of loss workdays are avoided. Cleaner air has positive impacts on visibility, erosion, animal and plant life, as well as a more healthy, productive society.

Due to the high number of affected equipment, high costs to install controls ($10 million to $70 million per project), competing demand for resources (e.g., trained labor pool, construction material), and concerns for long downtimes and disruptions affecting fuel supply, a staggered compliance schedule is being proposed. Flexibility is necessary to ensure a realistic and successful implementation while achieving anticipated emission reductions and providing cost savings. First, it was determined that some projects, due to a variety of reasons such as high costs and low reductions, would be extremely not cost effective individually even though BARCT determinations are calculated based on class and category. These outliers were removed from the cost-effective calculation for the determination of the BARCT limit and evaluated for a concentration limit up to when it would be cost effective. However, these "conditional" limits could only be applied to those projects satisfying certain criteria, such as equipment with no control installed post December 2015 when the RECLAIM shave was approved. Most eligible equipment is already controlled with no high emission reduction potential; therefore, facilities will experience a cost savings from avoiding an expensive SCR project and accepting a limit for the equipment operating at or near the conditional limit resulting in no additional or limited expense to further control, modify, tune or upgrade.

I-Plans are designed to provide facilities the ability to implement projects that best suit the timing of the projects to comply with emission reduction targets. This helps companies' better budget and plan so projects could occur during scheduled turnarounds, which provides a cost savings from not having to accelerate planning and schedule additional unplanned turnarounds. Additional turnarounds result in more costs from an additional lengthy design process and logistics, as well as facility downtime, loss of production and sales, and overall impact on the regional and state fuel supply that, in turn, can affect downstream businesses dependent on petroleum products. Figure below shows the percentage of required NOx reductions for implementations of I-Plans based on compliance schedule in Table 6 of PR 1109.1. Note that the reductions showed in the chart are based on estimated emission reductions from all equipment in the rule and 75% of the targeted emission reductions could be achieved in 2027. Note: bars represent the emission reductions based on the estimated start of the emission reduction projects (30 months from permit submittal deadline).

The figure below demonstrates the phased in emission reductions that will occur from Facilities with six or more Units complying with one of the Options in an I-Plan. Staff also calculated the early emission reductions that will occur prior to I-Plan implementation schedule. Staff estimates that 3.7 to 3.8 tons per day of NOx emission reductions, or 50 percent of the overall rule reductions, will be achieved by December 31, 2023. Those emission reductions are the result of the NOx emission reduction projects currently being implemented, Units that will likely achieve early reductions complying with Table 2 conditional limits and the largest refinery in the region reducing 50 percent of the required PR 1109.1 reductions by January 1, 2024 to comply with an approved B-Cap using I-Plan Option 4. The bar chart below only includes the emission reductions from the facility complying with I-Plan Option 4.

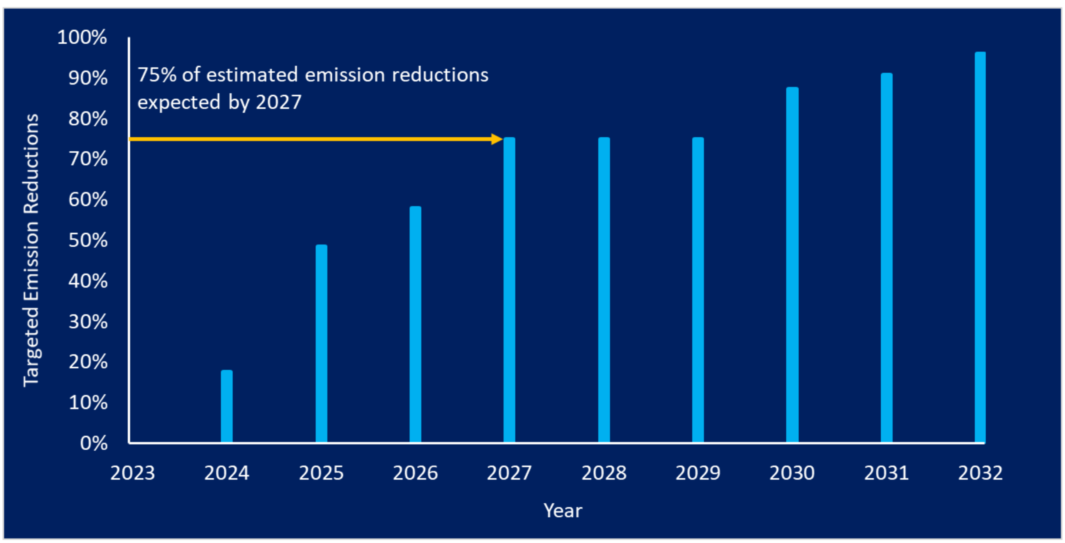


Figure 15. Percentage of Required NOx Reductions for Implementation of I-Plans

B-Plans, like the conditional limits, provide the facilities flexibility in deciding which projects are more cost effective to over-control and which overly expensive projects could be re-designed to be avoid high costs and yet meet the overall BARCT equivalent emission reductions in the aggregate. While to over-control one piece of equipment will be more costs, facilities under the B-Plan can calculate and decide whether the under-control of another piece of equipment is worth the trade-off. Most likely, cost will be a major factor in making that decision.

B-Caps are required to meet BARCT equivalent emission reduction targets but provide the flexibility in the day-to-day operation of the refinery equipment under a mass cap as opposed to stringent individual concentration limits. The overall emission reductions are the same but, similar to the B-Plan, facilities have the ability to decide which equipment will operate at certain levels in order to meet the required target. These decisions are likely to be made based on which equipment is most cost effective to install and operated controls, and which equipment is best to be shutdown and replaced, or just shutdown. Older equipment tends to be more expensive to retrofit and control, so shutting down or replacing will likely be less cost overall and more cost effective when seeking NOx emission reductions.

RULE ADOPTION RELATIVE TO COST-EFFECTIVENESS

On October 14, 1994, the Governing Board adopted a resolution that requires staff to address whether rules being proposed for amendment are considered in the order of cost-effectiveness. The 2016 AQMP ranked, in the order of cost-effectiveness, all the control measures for which costs were quantified. It is generally recommended that the most cost-effective actions be considered first. PR 1109.1 implements Control Measure CMB-05 which was ranked sixth in cost-effectiveness in the 2016 AQMP ranked Control Measure CMB-05.

SOCIOECONOMIC ASSESSMENT

The Draft Socioeconomic Impact Assessment for Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations, Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations, Proposed Amended Rule 1304 – Exemptions, and Proposed Amended Rule 2005 – New Source Review for RECLAIM was released on September 7, 2021, for a 60-day public review period.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

Pursuant to the California Environmental Quality Act (CEQA) and South Coast AQMD's Certified Regulatory Program (Public Resources Code Section 21080.5 and CEQA Guidelines Section 15251(l); codified in South Coast AQMD Rule 110), the South Coast AQMD is lead agency for the proposed project, which is comprised of Proposed Rules 1109.1 and 429.1, Proposed Amended Rules 1304 and 2005, and Proposed Rescinded Rule 1109. CEQA Guidelines Section 15187 requires an environmental analysis to be performed when a public agency proposes to adopt a new rule or regulation requiring the installation of air pollution control equipment or establishing a performance standard, which is the case with the proposed project. The South Coast AQMD has prepared a Subsequent Environmental Assessment (SEA) for the proposed project, which is a substitute CEQA document pursuant to CEQA Guidelines Section 15252, prepared in lieu of a Subsequent Environmental Impact Report. The SEA contains the environmental analysis required by CEQA Guidelines Section 15187 and tiers off of the December 2015 Final Program Environmental Assessment (PEA) for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM) (referred to as NOx RECLAIM) and the March 2017 Final Program Environmental Impact Report (EIR) for the 2016 Air Quality Management Plan as allowed by CEQA Guidelines Sections 15152, 15162, 15168 and 15385. The Draft SEA was released for a ~~45~~46-day public review and comment period to provide public agencies and the public an opportunity to obtain, review, and comment on the environmental analysis. ~~Comments made~~ The South Coast AQMD received six comment letters relative to the analysis in the Draft SEA and responses to the comments ~~will be~~have been included in the Final SEA.

Draft Findings Under California Health and Safety Code Section 40727

Requirements to Make Findings

California Health and Safety Code Section 40727 requires that prior to adopting, amending or repealing a rule or regulation, the South Coast AQMD Governing Board shall make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the public hearing, and in the staff report.

Necessity

Proposed Rule 1109.1 is needed to establish BARCT requirements for petroleum refineries and related operations, including facilities that will be transitioning from RECLAIM to a command-and-control regulatory structure. For this rule, affected facilities include asphalt plants, biofuel plants, hydrogen production plants, petroleum coke calcining facilities, sulfuric acid plants and sulfur recovery plants. In addition, Assembly Bill 617 requires facilities subject to a cap-and-trade program to be evaluated for BARCT.

Authority
The South Coast AQMD Governing Board has authority to adopt amendments to Proposed Rule 1109.1 pursuant to the California Health and Safety Code Sections 39002, 40000, 40001, 40440, 40702, 40725 through 40728, and 41508.

Clarity
Proposed Rule 1109.1 is written or displayed so that its meaning can be easily understood by the persons directly affected by it.

Consistency
Proposed Rule 1109.1 is in harmony with and not in conflict with or contradictory to, existing statutes, court decisions, or state or federal regulations.

Non-Duplication
Proposed Rule 1109.1 will not impose the same requirements as any existing state or federal regulations. The proposed amended rule is necessary and proper to execute the powers and duties granted to, and imposed upon, the South Coast AQMD.

Reference
In drafting Proposed Rule 1109.1, the following statutes which the South Coast AQMD hereby implements, interprets or makes specific are referenced: Health and Safety Code Sections 39002, 40000, 40001, 40702, 40440(a), 40440(b), 40440(c), 40725 through 40728.5, and 41508.

COMPARATIVE ANALYSIS

Under Health and Safety Code Section 40727.2, the South Coast AQMD is required to perform a comparative analysis when adopting, amending, or repealing a rule or regulation. The comparative analysis is relative to existing federal requirements, existing or proposed South Coast AQMD rules and air pollution control requirements and guidelines which are applicable to combustion equipment subject to PR 1109.1. The comparative analysis for PR 1109.1 can be found in the following two tables below.

Table 4-5. Comparative Analysis for PR 1109.1 with South Coast AQMD Rules

Rule Element	PR 1109.1	RECLAIM	Rule 1118.1	Rule 1134	Rule 1146	Rule 1147
Applicability	Units at petroleum refineries and facilities with related operations to petroleum refineries, including Asphalt Plants, Biofuel Plants, Hydrogen Production Plants, petroleum coke calcining facilities, Sulfuric Acid Plants, and Sulfur Recovery Plants	Facilities regulated under the NOx RECLAIM program (SCAQMD Reg. XX)	Flares that require a SCAQMD permit at non-refinery facilities, including, but not limited to, oil and gas production facilities, wastewater treatment facilities, landfills, and organic liquid handling facilities	Stationary gas turbines, 0.3 megawatt (MW) and larger. • Not applicable to stationary gas turbines subject to Rule 1135 located at petroleum refineries, landfills, or publicly owned treatment works; or fueled by landfill gas	Boilers, steam generators, and process heaters of equal to or greater than 5 million Btu per hour rated heat input capacity used in all industrial, institutional, and commercial operations	Ovens, dryers, dehydrators, heaters, kilns, calciners, furnaces, crematories, incinerators, heated pots, cookers, roasters, fryers, closed and open heated tanks and evaporators, distillation units, afterburners, degassing units, vapor incinerators, catalytic or thermal oxidizers, soil and water remediation units and other combustion equipment with nitrogen oxide emissions that require a District permit and are not specifically required to comply with a nitrogen oxide emission limit by other District Regulation XI rules
Requirements	NOx Limits at 24-hour Rolling Averaging Time unless specified otherwise: • Boilers <40 MMBtu/hr: 40 ppmv/ 5 ppmv @ replacement of 50% or more of the burners in a boiler or 50% or more of the heat input in a boiler • Process Heaters <40 MMBtu/hour: 40 ppmv/ 9 ppmv @ replacement of 50% or more of the burners in a process heater or 50% or more of the heat input in a process heater • Boilers and Process Heaters ≥40	**<u>RECLAIM 2005:</u>** • Boilers and Heaters <20 MMBtu/hr:12 ppmv • Boilers and Heaters ≥20–<40 MMBtu/hr: 9 ppmv • Boilers and Heaters ≥40–≤110 MMBtu/hr: 25 ppmv • Boilers and Heaters >110 MMBtu/hr: 5 ppmv • Petroleum Refining, Calciner: 30 ppmv • Petroleum Refining, FCCU: 85% reduction for FCCU and CO Boiler **<u>RECLAIM 2015:</u>** • Boilers and Heaters ≥40 MMBtu/hr: 2 ppmv @ 3% O_2 • Petroleum Refining, Calciner: 10 ppmv	• Non-Refinery Flares: Replacement with 20 ppmv flare (0.025 lb/MMBtu) if throughput capacity > 5%	For engines installed prior to January 1, 2012 • 12.7 g/hp-hr when max engine speed < than 130 rpm • 34 · $n^{-0.2}$ g/hp-hr) when 130 £ max engine speed < 2,000 rpm, where n is max engine speed; and • 7.3 g/hp-hr when max engine speed > 2,000 rpm For engines installed on or after January 1, 2012 and before January 1, 2016 • 10.7 g/hp-hr when max engine speed < 130 rpm; • 33 · $n^{-0.23}$ g/hp-hr) when 130 £ max engine speed < 2,000 rpm, where n is max engine speed; and	• Boilers and Heaters ≥75 MMBtu/hr: 5 ppmv • Boilers and Heaters <75 MMBtu/hr: 9 ppmv	• Calciner and Kiln (≥1200°F): 60 ppmv at 3% O_2 **<u>or</u>** 0.073 lb/MMBtu • Incinerator, Afterburner, Remediation Unit, and Thermal Oxidizer: 60 ppmv or 0.073 lb/MMBTU

Rule Element	PR 1109.1	RECLAIM	Rule 1118.1	Rule 1134	Rule 1146	Rule 1147
	MMBtu/hour: 5 ppmv @ 3% O_2 • FCCU: 2 ppmv @ 3% O_2 and 365-day Rolling Averaging Time 5 ppmv @ 3% O_2 and 7-day Rolling Averaging Time • Flares: 20 ppmv @ 3% O_2 • Gas Turbines fueled with Natural Gas: 2 @ 15% O_2ppmv • Gas Turbines fueled with Gaseous Fuel other than Natural Gas: 3 ppmv @ 15% O_2 • Petroleum Coke Calciner: 5 ppmv @ 3% O_2 and 365-day Rolling Averaging Time 10 ppmv @ 3% O_2 and 7-day Rolling Averaging Time • SMR Heaters: 5 ppmv @ 3% O_2 • SMR Heaters with Gas Turbine: 5 ppmv @ 15% O_2 • SRU/TG Incinerators: 30 ppmv @ 3% O_2 • Sulfuric Acid Furnaces: 30 ppmv @ 3% O_2 and 365-day Rolling Averaging Time • Vapor Incinerators: 30 ppmv @ 3% O_2	• Petroleum Refining, FCCU: 2 ppmv @ 3% O_2, dry • Refinery Gas Turbines: 2 ppmv @ 15% O_2, dry • Sulfur Recovery Units/Tail Gas Incinerator: 2 ppmv NOx @ 3% O_2, dry		• 5.7 g/hp-hr) when max engine speed > 2,000 rpm. For engines installed on or after January 1, 2016, • 2.5 g/hp-hr when max engine speed < 130 rpm; • 6.7 · $n^{-0.20}$ g/hp-hr) when 130 £ max engine speed < 2,000 rpm, where n is max engine speed; and • 1.5 g/hp-hr when max engine speed > 2,000 rpm.		
Reporting	Submit all source test reports, including the source test results and a description of the unit tested, to the Executive Officer within 60 days of completion of the source test	• Daily electronic reporting for major sources • Monthly to quarterly reporting for large sources and process units • Quarterly Certification of Emissions Report and Annual Permit Emissions Program for all units	Annual report	• Comply with SCAQMD Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions to demonstrate compliance with the NOx emissions limits of this rule • Determine eligibility of the low-use exemption for each stationary gas turbine	None	None

Rule Element	PR 1109.1	RECLAIM	Rule 1118.1	Rule 1134	Rule 1146	Rule 1147
				annually and report to the Executive Officer no later than March 1 following each reporting year		
Monitoring	• For a unit with a rated heat input capacity of greater than or equal to 40 MMBtu/hour in a Former RECLAIM Facility install, certify, operate, and maintain a CEMS to measure NOx and O_2 pursuant to the applicable Rule 218.2 and Rule 218.3 requirements • For a unit with no CEMS, conduct a source test, with a duration of at least 60 minutes but no longer than 120 minutes • Maintain CEMS for all applicable equipment or an enforceable method approved by the Executive Officer to determine daily mass emissions for units without CEMS under B-Cap • If source test is applicable, conduct the source test using a South Coast AQMD approved contractor under the Laboratory Approval Program • For a unit required to perform a source test every 36 months, perform diagnostic emissions checks of NOx, CO, and O_2 emissions with a portable NOx, CO, and	• A continuous in-stack NOx monitor for major sources • Source testing once every 3 years for large sources • Source testing once every 5 years for process units	Install and operate a fuel meter for each gas or vapor, excluding pilot gas, routed to every flare or flare station	• Conduct monitoring pursuant to SCAQMD Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions • Each stationary gas turbine with a catalytic control device shall conduct source testing or utilize an ammonia continuous emission monitoring system certified under an approved SCAQMD protocol to demonstrate compliance with the ammonia emission limit • Installation of an ammonia continuous emission monitoring system certified under an approved SCAQMD protocol if an extension is requested beyond 12 months to comply with the ammonia emission limits • Each stationary gas turbine operating without a continuous emission monitoring system and emitting 25 tons or more of NOx per calendar year shall perform source tests to demonstrate compliance with the NOx emission limits at least once every calendar year. • Each stationary gas turbine operating without a continuous emission monitoring system and	• Any unit(s) with a rated heat input capacity greater than or equal to 40 million Btu per hour and an annual heat input greater than 200 x 109 Btu per year shall have a continuous in-stack nitrogen oxides monitor or equivalent verification system in compliance with Rule 218 and Rule 218.1 • For air pollution control equipment with ammonia emissions: 1) Conduct quarterly a source test to demonstrate compliance with the ammonia emission limit, according to the procedures in District Source Test Method 207.1 for Determination of Ammonia Emissions from Stationary Sources, during the first 12 months of unit operation and thereafter, except that source tests may be conducted annually within 12 months thereafter when four consecutive quarterly source tests demonstrate compliance with the ammonia emission limit **OR** 2) Utilize an ammonia Continuous Emissions Monitoring System (CEMS) certified under an approved South Coast AQMD protocol to demonstrate compliance with the ammonia emission limit • Compliance with the NOx and CO emission requirements shall be determined using a South Coast AQMD approved contractor under the Laboratory	• Owners or operators of units shall determine compliance with the applicable emission limit using a District approved test protocol • Install and maintain in service non-resettable, totalizing, fuel meters for each unit's fuel(s) for a unit complying with applicable limit using pounds per million BTU

Rule Element	PR 1109.1	RECLAIM	Rule 1118.1	Rule 1134	Rule 1146	Rule 1147
	O_2 analyzer every 365 days or every 8760 operating hours, whichever occurs earlier • Provisions for Source Test Schedule for Units with and without Ammonia Emissions in the Exhaust			emitting less than 25 tons shall perform source tests to demonstrate compliance with the NOx emission limits at least once every three calendar years. • Each stationary gas turbine with a catalytic control device not utilizing an ammonia continuous emission monitoring system shall conduct source tests quarterly to demonstrate compliance during the first twelve months of operation of the catalytic control device and every calendar year thereafter when four consecutive source tests demonstrate compliance with the ammonia emission limit. If a source test is failed, four consecutive quarterly source tests shall demonstrate compliance with the ammonia emissions limits prior to resuming source tests annually	Approval Program according to specific procedures: (A) Every three years for units with a rated heat input capacity greater than or equal to 10 million Btu per hour, except for units subject to paragraph (c)(5) (B) Every five years for units with a rated heat input capacity less than 10 million Btu per hour down to and including 5 million Btu per hour • Diagnostic emission checks of NOx emissions with a portable NOx, CO, and oxygen analyzer according to the Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen	
Recordkeeping	• Operating log • Maintain daily records of mass emissions, in pounds (lbs) per day, from all units included in an approved B-Cap • Keep and maintain the following records on-site for five years and make them available to the Executive Officer upon request: (A) CEMS data; (B) Source tests reports; (C) Diagnostic emission checks; and (D) Written logs of startups, shutdowns,	• Quarterly log for process units • < 15-min. data = min. 48 hours; ≥ 15-min. data = 3 years (5 years if Title V) • Maintenance & emission records, source test reports, RATA reports, audit reports and fuel meter calibration records for Annual Permit Emissions Program = 3 years (5 years if Title V)	• Maintain records of annual throughput attributed to source testing and utility pipeline curtailment • Maintain a copy of the manufacturer's, distributor's, installer's or maintenance company's written maintenance schedule and instructions • Retain all written or electronic records for at least five years and make them available no later than five business days from date requested	• Conduct recordkeeping pursuant to SCAQMD Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions • All records shall be maintained at the facility for a period of two years and made available to SCAQMD staff upon request. • Maintain a gas turbine operating log that includes, on a daily basis, the actual start-up and shut-down times; total hours of	• Records of all monitoring data shall be maintained for a rolling twelve-month period of two years (five years for Title V facilities) and shall be made available to South Coast AQMD personnel upon request • The owner or operator of any unit(s) selecting the tune-up option shall maintain records for a rolling 24-month period verifying that the required tune-ups have been performed	• Records of source tests shall be maintained for ten years and made available to District personnel upon request • Maintain on site at the facility where the unit is being operated a copy of the manufacturer's, distributor's, installer's or maintenance company's written maintenance schedule and instructions and retain a record of the maintenance activity for a period of not less than three years

Rule Element	PR 1109.1	RECLAIM	Rule 1118.1	Rule 1134	Rule 1146	Rule 1147
	and breakdowns, all maintenance, service and tuning records, and any other information required by this rule • Data gathered or computed for intervals of less than 15 minutes shall be maintained for a minimum of 48 hours			operation; type and quantity of fuel used (liquid/gas); cumulative hours of operation to date for the calendar year		• Maintain on site a copy of all documents identifying the unit's rated heat input capacity for as long as the unit is retained on-site

Table 4-6. Comparative Analysis for PR 1109.1 with Federal Requirements

	PR 1109.1	CFR, Title 40, Vol. 7, Part 60, Subpart Db	CFR, Title 40, Vol. 7, Part 60, Subpart GG	CFR Title 40, Vol. 7, Part 60, Subpart Ja	CFR, Title 40, Vol. 8, Part 60, Subpart KKKK
Applicability	Units at petroleum refineries and facilities with related operations to petroleum refineries, including Asphalt Plants, Biofuel Plants, Hydrogen Production Plants, petroleum coke calcining facilities, Sulfuric Acid Plants, and Sulfur Recovery Plants	Steam generating units that commenced construction, modification, or re-construction after 6/19/1984 and that has a heat input capacity of >29 MW (100 MMBtu/hr)	Gas turbines with heat input of ≥10 MMBtu/hr that commenced construction, modification or re-construction on or before 2/18/2005	Fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares and sulfur recovery plants. • For flares, the provisions of this subpart apply only to flares which commence construction, modification or reconstruction after June 24, 2008	Gas turbines with heat input of ≥10 MMBtu/hr that commenced construction, modification or re-construction after 2/18/2005
Requirements	NOx Limits at 24-hour Rolling Averaging Time unless specified otherwise: • Boilers <40 MMBtu/hr: 40 ppmv/ 5 ppmv @ replacement of 50% or more of the burners in a boiler or 50% or more of the heat input in a boiler • Process Heaters <40 MMBtu/hour: 40 ppmv/ 9 ppmv @ replacement of 50% or more of the burners in a process heater or 50% or more of the heat input in a process heater • Boilers and Process Heaters ≥40 MMBtu/hour: 5 ppmv @ 3% O_2 • FCCU: 2 ppmv @ 3% O_2 and 365-day Rolling Averaging Time 5 ppmv @ 3% O_2 and 7-day Rolling Averaging Time • Flares: 20 ppmv @ 3% O_2 • Gas Turbines fueled with Natural Gas: 2 @ 15% O_2 ppmv • Gas Turbines fueled with Gaseous Fuel other than Natural Gas: 3 ppmv @ 15% O_2 • Petroleum Coke Calciner: 5 ppmv @ 3% O_2 and 365-day Rolling Averaging Time 10 ppmv @ 3% O_2 and 7-day Rolling Averaging Time • SMR Heaters: 5 ppmv @ 3% O_2 • SMR Heaters with Gas Turbine: 5 ppmv @ 15% O_2 • SRU/TG Incinerators: 30 ppmv @ 3% O_2	NOx limits (30-day rolling average): • Natural gas and distillate oil, except duct burners in combined cycle systems: 43 ng/J (low heat release), 86 ng/J (high heat release) • Residual Oil: 130 ng/J (low heat release), 170 ng/J (high heat release) • Coal: 210 ng/J (mass-feed stoker), 260 ng/J (spreader stoker and fluidized bed combustion), 300 ng/J (pulverized coal), 260 ng/J (Lignite), 340 ng/J (Lignite mined in North Dakota, South Dakota or Montana and combusted in a slag tap furnace), 210 ng/J (coal-derived synthetic fuels) • Duct burner in a combined cycle system: 86 ng/J (natural gas and distillate oil), 170 ng/J (residual oil) • Affected facility that simultaneously combusts natural gas and/or distillate oil with a potential SO_2 emissions rate of ≤26 ng/J with wood, municipal-type solid waste, or other solid fuel, except coal: 130 ng/J • Affected facility that commenced construction after July 9, 1997: 86 ng/J (combusts coal, oil, or natural gas, or any combination of the three)	Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired: • NOx Concentration (percent by volume @ 15% O_2) = 0.0150* (14.4/Y) + F where: Y = Manufacture's rated heat input F = NOx emission allowance for fuel-bound nitrogen	FCCU & FCU: • NOx: 80 ppmv, 7-day rolling average • CO: 500 ppmv, hourly average Process heaters > 40 MMBtu/hr (30 day rolling average): • 40 ppmv or 0.040 lb/MMBtu for natural draft process heaters • 60 ppmv or 0.060 lb/MMBtu for forced draft process heaters • 150 ppmv or Equation 3 for co-fired natural draft process heaters • 150 ppmv or Equation 4 for co-fired forced draft process heaters For flares, develop and implement a written flare management plan *All emission limits are dry @ 0% excess air	NOx limit @ 15% O_2: • new, firing natural gas, electric generating ≤50 MMBtu/hr – 42 ppm • new, firing natural gas, mechanical drive ≤50 MMBtu – 100 ppm • new, firing natural gas >50 MMBtu/hr and ≤850 MMBtu/hr – 25 ppm • new, modified, or reconstructed, firing natural gas >850 MMBtu/hr – 15 ppm • new, firing fuels other than natural gas, electric generating ≤50 MMBtu/hr – 96 ppm • new, firing fuels other than natural gas, mechanical drive ≤50 MMBtu/hr – 150 ppm • new, firing fuels other than natural gas >50 MMBtu/hr and ≤850 MMBtu/hr – 74 ppm • new, modified, or reconstructed, firing fuels other than natural gas >850 MMBtu/hr – 42 ppm • modified or reconstructed ≤50 MMBtu/hr – 150 ppm • modified or reconstructed, firing natural gas >50 MMBtu/hr and ≤850 MMBtu/hr – 42 ppm • modified or reconstructed, firing fuels other than natural gas >50 MMBtu/hr and ≤850 MMBtu/hr – 96 ppm

	PR 1109.1	CFR, Title 40, Vol. 7, Part 60, Subpart Db	CFR, Title 40, Vol. 7, Part 60, Subpart GG	CFR Title 40, Vol. 7, Part 60, Subpart Ja	CFR, Title 40, Vol. 8, Part 60, Subpart KKKK
	• Sulfuric Acid Furnaces: 30 ppmv @ 3% O_2 and 365-day Rolling Averaging Time Vapor Incinerators: 30 ppmv @ 3% O_2				
Reporting	Submit all source test reports, including the source test results and a description of the unit tested, to the Executive Officer within 60 days of completion of the source test	• Performance test results, notification of the initial startup, design heat input capacity, fuels to be combusted, a copy of any federally enforceable requirement that limits the annual capacity factor, annual capacity factor, emerging technology used for SO_2 emissions; reports of excess emissions	• Semi- annual reports of excess emissions and monitor downtime	• Semi- annual reports of excess emissions and monitor downtime. Notification of the specific monitoring provisions the owner or operator intends to comply with.	• Semi- annual reports of excess emissions and monitor downtime. Annual performance test results.
Monitoring	• For a unit with a rated heat input capacity of greater than or equal to 40 MMBtu/hour in a Former RECLAIM Facility install, certify, operate, and maintain a CEMS to measure NOx and O_2 pursuant to the applicable Rule 218.2 and Rule 218.3 requirements • For a unit with no CEMS, conduct a source test, with a duration of at least 60 minutes but no longer than 120 minutes • Maintain CEMS for all applicable equipment or an enforceable method approved by the Executive Officer to determine daily mass emissions for units without CEMS under B-Cap	• Performance tests with either of following Test Methods: – Method 19, Method 3A or 3B, Method 5, 5B, or 17, Method 5, Method 17, Method 1, Method 9, Method 7E, Method 7,7A, 7E, Method 320 • Quarterly accuracy determinations and daily calibration drift tests for CEMS	• Performance test with either of following Test Methods: – EPA Method 20; ASTM D6522-00; EPA Method 7E and either EPA Method 3 or 3A; sampling traverse points following Method 20 or Method 1, and sampled for equal time intervals • A continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel (averaged over one hour) or CEMS consisting of NOx and O_2 monitors for stationary gas turbines that commenced construction, reconstruction, or modification after October 3, 1977, but before July 8, 2004, and which uses	• Initial performance test with either of following Test Methods: – Method 1 of Appendix A-1 to part 60, Method 2 of appendix A-1 to part 60, Method 3, 3A, or 3B of appendix A-2 to part 60, Method 5, 5B, or 5F of appendix A-3 to part 60, Method 7, 7A, 7C,7D or 7E of appendix A-4 to part 60, Method 10, 10A, or 10B of appendix A-4 to part 60, Method 6, 6A, or 6C of appendix A-4 to part 60, Method 15 or 15A of appendix A-5 to part 60, Method 16 of appendix A-6 to part 60, Method 11, Method 18 of appendix A-6 to part 60, Method 2, 2A, 2B, 2C or 2D of appendix A–2 to part 60	• Initial performance test with either of following Test methods: – EPA Methods 7E and 3A, EPA Method 20, EPA Method 19 • A continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel or CEMS for stationary gas turbines using water or steam injection (hourly average) • Annual performance tests or continuous monitoring for turbines without water or steam injection

	PR 1109.1	CFR, Title 40, Vol. 7, Part 60, Subpart Db	CFR, Title 40, Vol. 7, Part 60, Subpart GG	CFR Title 40, Vol. 7, Part 60, Subpart Ja	CFR, Title 40, Vol. 8, Part 60, Subpart KKKK
	• If source test is applicable, conduct the source test using a South Coast AQMD approved contractor under the Laboratory Approval Program • For a unit required to perform a source test every 36 months, perform diagnostic emissions checks of NOx, CO, and O_2 emissions with a portable NOx, CO, and O_2 analyzer every 365 days or every 8760 operating hours, whichever occurs earlier Provisions for Source Test Schedule for Units with and without Ammonia Emissions in the Exhaust		water or steam injection to control NOx emissions (averaged over one hour)	– ASTM D1945–03, ASTM D1946–90, ASTM D6420–99, ASTM UOP539–97 – ASME MFC–3M–2004, ANSI/ASME MFC–4M–1986, ASME MFC–6M–1998, ASME/ANSI MFC–7M–1987, ASME MFC–11M–2006, ASME MFC–14M–2003, ASME MFC–18M–2001, ANSI/ASME–MFC–5M–1985, ASME/ANSI MFC–9M–1988, ASME MFC–16–2007, ASME MFC–22–2007 – AGA Report No. 3, Part 1, AGA Report No. 3, Part 2, AGA Report No. 11, AGA Report No. 7 – API Manual of Petroleum Measurement Standards, Chapter 22, Section 2 – ISO 8316 – ASTM D240–02, ASTM D1826–94, ASTM D1945–03, ASTM D1946–90, ASTM D3588–98, ASTM D4809–06, ASTM D4891–89 – GPA 2261–00, GPA 2172–09 • FCCU & FCU subject to a PM limit: continuous parameter monitor systems, bag leak detection system, CEMS, or an instrument for continuously monitoring the opacity of emissions • FCCU & FCU subject to NOx, SO_2 or CO limit: CEMS • Process heaters with a NOx limit: CEMS • Process heaters with a mass-based or heating value-based limit NOx limit: Fuel gas flow and fuel oil flow monitors • CPMS flow monitoring for flares	

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Recordkeeping	• Operating log • Maintain daily records of mass emissions, in pounds (lbs) per day, from all units included in an approved B-Cap • Keep and maintain the following records on-site for five years and make them available to the Executive Officer upon request: (A) CEMS data; (B) Source tests reports; (C) Diagnostic emission checks; and (D) Written logs of startups, shutdowns, and breakdowns, all maintenance, service and tuning records, and any other information required by this rule Data gathered or computed for intervals of less than 15 minutes shall be maintained for a minimum of 48 hours	• Performance testing; emission rates; daily records of the amounts of each fuel combusted; calculations of the annual capacity factor for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste; nitrogen content; opacity; hours of operation. Records are required to be maintained for 2 years	• Performance testing; emission rates; monitoring data; CEMS audits and checks; occurrence and duration of any startup, shutdown, or malfunction	• Performance testing; emission rates; monitoring data; CEMS audits and checks; occurrence and duration of any SSM; flare management plan; conformance with bag leak detection system O&M; bag leak detection system alarms and actions; FCCU & FCU coke-burn off rate and hours of operation; records of emissions > 500 lbs SO_2; qualification for exemptions; time periods during which the sulfur pit vents were not controlled and measures taken to minimize emissions during these periods	• Performance testing; emission rates; monitoring data; CEMS audits and checks; occurrence and duration of any startup, shutdown, or malfunction

REFERENCES

Draft Final Staff Report of Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM. South Coast AQMD, December 4, 2015.

Dynamic Control of SCR Minimum Operating Temperature. C. A. Lockert, P. C. Hoeflich, and L. S. Smith. Power-Gen International, December 2009.

APPENDIX A NOX FORMATION AND CONTROL TECHNOLOGIES

NOx Formation

The combustion of fuels results in NOx emissions which refers collectively to oxide of nitrogen (NO) and nitrogen dioxide (NO_2). There are three prominent formation mechanisms by which NOx is generated in combustion processes: Thermal NOx, Fuel NOx, and Prompt NOx. Most combustion control techniques are designed around the concept of reducing thermal and/or fuel NOx. Post-combustion techniques reduce NOx in the flue gas regardless of the formation mechanism.

Thermal NOx Formation

Thermal NOx is formed through a high temperature reaction (hence, the name "Thermal" NOx) between molecular nitrogen and oxygen present in the combustion air by the well-known Zeldovich mechanism (reaction 1). The formation of thermal NOx is dependent upon the molar concentrations of nitrogen and oxygen and the temperature of combustion. Therefore, most NOx techniques that control thermal NOx formation at the source focus on reducing peak flame temperature or concentrations of the reactants (N_2 and O_2). Combustion at temperatures below 2,400°F forms lower concentrations of NOx, whereas thermal NOx formation increases exponentially at temperatures above 2,600°F and linearly with increases in residence time.

$N_2 + O_2 \rightarrow NO, NO_2$ (1)

Fuel NOx Formation

Fuel NOx is formed through the reactions of nitrogen-containing organic compounds in the fuel (hence, the name "Fuel" NOx) with oxygen in the combustion air. The bond between atoms of nitrogen and other chemical elements, such as carbon, in fuels is not as strong as the nitrogen bond found in molecular nitrogen (i.e., triple, N≡N). The overall reaction is as follows:

$R\text{-}N + O_2 \rightarrow NO, NO_2, CO_2, H_2O$, trace species (2)

Fuel NOx formation is typically not a concern in refinery equipment that fire natural gas or refinery fuel gas because they contain little or no fuel-bound nitrogen. Molecular nitrogen (N_2) in natural gas does not contribute significantly to fuel NOx formation because of the stronger nitrogen inter-bond than those of nitrogen compounds. Fuel NOx is not a concern for gaseous fuels like natural gas, propane, or refinery gas, which normally have no nitrogen-containing organic compounds. Fuel NOx is not a major contributor to overall NOx emissions from refinery equipment and may be important when oil, coal, or waste fuels (e.g., landfill gas) are used, which may contain significant amounts of organically bound nitrogen. However, fuel NOx is a concern if the equipment burns distillates or residual oils because these fuels contain nitrogen-bearing species.

Prompt NOx Formation

Prompt NOx formation occurs when nitrogen-containing fuels are burned in fuel-rich combustion conditions through a relatively fast reaction (hence, the name "Prompt" NOx) between nitrogen, oxygen, and hydrocarbon radicals (reaction 3).

$R + O_2 + N_2 \rightarrow NO, NO_2, CO_2, H_2O$, trace species (3)

Prompt NOx is generally an important mechanism in lower-temperature combustion processes, but it is less important compared to thermal NOx formation at the higher temperatures which are common in many refinery combustion units.

Fluidized Catalytic Cracking Units (FCCU) NOx Formation

The FCCU is a unique process where NOx formation occurs as a result of coke burn off from the catalyst in the regenerator section of the unit. The coke on the catalyst is the result of the hydrocarbon feed (vacuum gas oil) to the FCCU which contains nitrogen-bound species that form precursors such as ammonia and cyanide as the coke is burned off the catalyst. These precursors will further convert to NOx depending on regenerator design and operating conditions. Unlike other refinery combustion equipment, thermal NOx is not a significant factor in the regenerator since operating temperature is <1,500 ºF. All the FCCUs within the South Coast Air District currently operate in full burn mode, so NOx contribution from the CO boiler burners is not a concern – CO boilers are operated as a heat recovery device only and are unfired.

Fuel Type

Most, if not all, fuels combusted at a refinery are gaseous fuels and consist of various fuel types. Fuel type has an impact on NOx emissions due to varying higher heating value (HHV) content of the fuel. There are several fuel types that are used in the combustion equipment impacted by PR 1109.1. Refinery fuel gas and natural gas are the predominant fuels used at refineries within the South Coast AQMD. Most of the refinery heaters and boilers are permitted to use both refinery gas and natural gas. One refinery operates a CO boiler that combust CO-rich off-gas from the FCC in addition to refinery gas and natural gas. For the purposes of the BARCT assessment, combustion equipment is further segregated into separate categories based on their fuel type, overall process type, and specific application.

Refinery Fuel Gas

Refinery fuel gas (RFG) is a by-product of the petroleum refining process and the predominant fuel for most refinery combustion equipment. RFG is comprised of methane, olefins, hydrogen, and H_2S, and its composition varies amongst the five refineries. Varying composition of RFG results in variations in HHV which can potentially impact the formation of NOx.

Firing RFG will generally result in higher thermal NOx formation than firing natural gas due to the higher flame temperatures caused by higher hydrogen and olefin content in RFG. This is a consideration when establishing limits for units requiring combustion modification through application of NOx controls such as low-NOx burners (LNB) or Ultra-low NOx burners (ULNB). Depending on the volume of RFG generated at each facility, natural gas is often used as make-up fuel to the refinery fuel gas system which dilutes some of the hydrogen and olefin concentrations moderating the impact on NOx emissions.

Natural Gas

Natural gas used as a fuel source is generally referred to as "pipeline quality natural gas" and is composed of at least 70 percent methane by volume. Natural gas contains other light hydrocarbons such as ethane, propane, and butanes, but it is being "sweetened" or desulfurized before sending into a pipeline. Natural gas typically has a higher heating value (HHV) between 950 and 1,100 Btu per standard cubic feet and does not vary as much as refinery fuel gas.

Pressure Swing Adsorption Off-gas or Purge Gas

Pressure swing adsorption off-gas or purge gas (PSA off-gas) is a combustion fuel source used in SMR heaters that are equipped with a PSA system. PSA system separates and recovers high purity hydrogen as a continuous supply for use in refinery hydro-processing units. The remaining gas contains hydrogen, methane, and carbon dioxide which has heating value and is purged out of the PSA system and is routed to the burners of the SMR heater as a combustion fuel source.

Hydrogen Sulfide and Sulfur

Sulfuric acid manufacturing plants combust sulfur-bearing species to generate SO_2. The SO_2 then goes through a series of steps where it is converted into sulfuric acid. Hydrogen sulfide and sulfur does not serve as a fuel source per se, but since both provide heating value, they can act as combustion fuel sources. The greater the ratio of sulfur species are in the feedstock being sent to the furnace, the less the demand will be for supplemental fuel such as natural gas or refinery fuel gas.

NOx Control Principles

In the petroleum refining industry, there are five NOx control principles that control technologies or techniques rely on. These principles are listed in the table below and discussed in the subsequent sections.

Table A-1. NOx Control Principles

Principles	Description	Control Technologies
Reduce Peak Flame Temperature	Excess of fuel, air stream, or flue gas to reduce temperature in the combustion zone lowering thermal NOx formation	Low NOx Burners (LNB), Ultra Low NOx Burners (ULNB), Flue Gas Recirculation (FGR), Water or Steam Injection, Staged Air or Staged Fuel
Reduce Residence Time	Prevents formation of thermal NOx	Injecting Air, Fuel, or Steam
Chemical Reduction of NOx	Chemically reducing/removing oxygen from NOx to form N_2	Selective Catalytic Reduction, Selective Non-Catalytic Reduction
Oxidation of NOx with absorption	Convert NOx to N_2O_5 using, ozone, or H_2O_2 with subsequent scrubber	Injection of Oxidant and removal with wet scrubber (LoTOx™)
Removal of N_2 Species	Removal of N_2 as a reactant in the combustion process	Low Nitrogen fuel, Using Oxygen Instead of Air
Combination of Principles	Methods above can be combined to achieve higher NOx reduction	LNB/ULNB with SCR or LoTOx™

Reducing Peak Flame Temperature

The ideal stoichiometric air-fuel ratio of combustion produces higher flame temperatures that generate higher thermal NOx concentrations. By avoiding the ideal stoichiometric air-fuel ratio, combustion temperatures can be reduced, and thus reducing thermal NOx formation. Reducing the overall peak flame temperature involves cooling the primary combustion zone with an excess of fuel, air, flue gas, or steam. This principle prevents most of the nitrogen from ionizing which lowers the number of present reactants for the formation of NOx. This principle is typically employed by burner control technologies.

Reducing Residence Time

This technique is used in boiler LNB applications by rapidly mixing and restricting the flame to a short region where the combustion air converts to flue gas. This is immediately followed by injection of fuel, air, or recirculating flue gas. Similar to reducing peak flame temperature, the short residence time prevents the nitrogen from being ionized and reacting with the O_2.

Chemical Reduction of NOx

This technique uses a reducing agent such as ammonia or urea to remove oxygen from NOx to convert it to nitrogen and water. SCR and selective non-catalytic reduction (SNCR) use this principle to remove NOx from the flue gas. SCR is an effective technology most widely used in the refining industry and can be applied to nearly all refinery combustion sources in PR 1109.1.

Oxidation of NOx with absorption

This technique involves using either a catalyst, injecting hydrogen peroxide, or injecting ozone into the flue gas air flow and oxidizing the NOx where it is converted into water soluble N_2O_5. A scrubber is added to the process where N_2O_5 is absorbed into liquid phase resulting in a nitric acid solution that can either be neutralized prior to discharge or sold. LoTOx™ is a control technology that utilizes this principle and has been employed in FCCU refinery applications.

Removal of N_2 Species

This principle involves removing nitrogen by using oxygen instead of air in the combustion process. This technique is not commonly employed or practical for refinery applications.

Combination of Principles

Many of the listed principles can be combined to achieve a lower NOx concentration level than achievable levels by each single method. The maximum degree of NOx reduction is possible when principles are combined. For example, for the case of a refinery process heater, combining LNB/ULNB with post-combustion control such as SCR, can achieve 95% or greater NOx reduction if the controls are designed and engineered properly. Based on emissions data and equipment information, process heaters with combination of properly engineered NOx controls can achieve less than 2 ppmv NOx. However, available control technologies are limited when factors such as turndown ratio, stability of flame, availability or access to burners, and costs are taken into consideration.

NOx Control Technologies

This section outlines the control technologies that are commercially available and have been implemented throughout the refining industry or other industrial applications. The technologies are considered mature technologies if they have been in use for more than 30 years. With advances in computational fluid dynamics (CFD) and cold flow modeling, technology vendors have improved their understanding and have optimize their designs to function the greatest efficiency. Control technologies can be classified into two categories: combustion control and post-combustion control.

PR 1109.1 will focus on control technology options for the seven refinery source categories. Each source category has its unique challenges and implementation approach which will be discussed further in the section for each specific source category.

As part of the combustion control assessment, staff met with the three major burner manufacturers:

- John Zink Hamworthy Combustions
- Zeeco
- Callidus Technologies

All three process burner manufacturers have extensive experience in the refining sector along with a large process burner portfolio for various refinery applications. Their products can be found in many refinery related units within the South Coast Air District and throughout the world. Staff met with all three burner manufacturers to gather insight on the current state of process burner technology and advancements. For SCR technology, staff met with the two major catalyst manufacturers and suppliers: Umicore and Cormetech, both companies are world leaders in SCR catalyst technology and provide catalyst to many industrial sectors including petroleum refining. In addition, staff also met with SCR system designer CECO Peerless. The company has over 30 years of experience and expertise in new SCR construction and retrofit. Their SCR systems are engineered for optimal performance that can reduce NOx emissions by up to 95%.

Combustion Controls

Combustion controls are techniques that reduce NOx by modifying the combustion zone through installation of LNBs, ULNB, DLN or DLNE combustors, water or steam injection, and flue gas recirculation (FGR). Control techniques employ air staging or fuel staging techniques to maximize NOx reduction. This technique reduces the adiabatic peak flame temperature and is effective at reducing thermal NOx formation. Fuel NOx is not a concern in refinery combustion equipment since refinery fuel gas contains nearly zero nitrogen content. If combustion modification is not an option for reducing NOx emissions in certain refinery applications, such as the FCCU and petroleum coke calciner, post-combustion or flue gas treatment controls such as SCR, UltraCat™, or LoTOx™ can be used to reduce NOx in the flue gas stream. This section will also discuss several emerging combustion control technologies that have reached the commercial demonstration/licensing but are not commonly used. These emerging technologies have limited data available for source specific applicability. However, they show to be highly effective in reducing NOx emissions in their current stage of development.

BURNER CONTROL TECHNOLOGIES

Low NOx Burners and Ultra-low NOx Burners

There are several commercially available burner control technologies that can be applied to existing process heaters, boilers, or furnaces. Burners are typically classified based on their NOx emissions as: conventional, low-NOx (LNB), ultra-low NOx (ULNB), and next-generation ultra-low NOx burners. However, there is no industry standard or clear definition of what constitutes a LNB or ULNB. According to staff's recent discussions with John Zink Hamworthy Combustions, ULNB can be any LNB that utilizes internal flue gas recirculation or other advanced techniques to control the flame temperature that minimizes NOx generation. Process burners are typically custom designed for each application and several factors must be considered prior to selecting a burner. Replacing conventional burners with LNB or ULNB often requires special attention because of the flame dimensions and limited space within a refinery process heater.

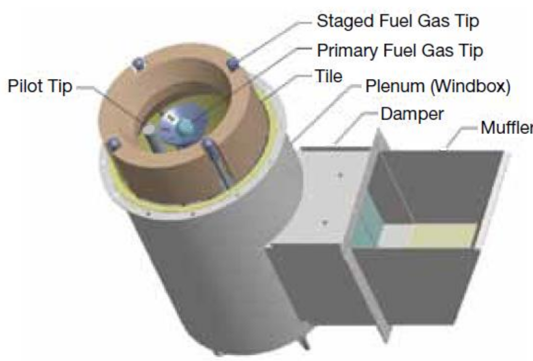

Figure A-1. Low NOx Burner Design

The American Petroleum Institute (API) 560 and 535, provides guidelines for the fired heaters and burners used for general refinery service. Recommended guidelines establish minimum requirements such as burner spacing, mechanical design, and higher heat density for optimal operation. Some manufacturers will guarantee ULNB performance to be <15 ppmv NOx from firing refinery fuel gas, however compliance tests for recent installations show that ULNBs operate at <25 ppmv. Burner performance is dependent on multiple factors, including burner orientation and arrangement, firebox size, heater type (force or natural draft), and fuel type. Using burners such as LNB or ULNB does not guarantee the NOx levels guaranteed by manufacturers. NOx emissions from burner will vary in real world applications due to specifics of the heater. Newer burner control technology (e.g., staged fuel burner, staged air burner, flue gas recirculation burner) will typically performs better than conventional burners (e.g., premix burner, raw gas burner).

It is important to note that in the South Coast Air District, most refinery process heaters have been retrofitted with first generation LNB or ULNB within the last 35 years under the RECLAIM program and they typically achieve NOx emission levels between 30 and 60 ppmv. Burner technology advancements make them good candidates for upgrades or retrofits to newer generation burners.

DRY LOW-NOX (DLN) OR LEAN PREMIX EMISSION COMBUSTORS (DLE COMBUSTORS)

Prior to combustion, gaseous fuel and compressed air are pre-mixed, minimizing localized hot spots that produce elevated combustion temperatures and therefore, less NOx is formed. Atmospheric nitrogen from the combustion air is mixed with air upstream of the combustor at deliberately fuel-lean conditions. Approximately twice as much air is supplied as is needed to burn the fuel. This excess air is a key to limiting NOx formation, since very lean conditions cannot produce the high temperatures that create thermal NOx. Using this technology, NOx emissions have been demonstrated at single digits (< 9 ppmv at 15% oxygen on a dry basis) without further controls. The technology is engineered into the combustor that becomes an intrinsic part of the turbine design. Fuel staging or air staging is utilized to keep the flame within its operating boundaries. DLN is not available as a "retrofit" technology and must be designed for each turbine application. Post-combustion control such as SCR and the most effective and cost-effective option for NOx control in gas turbines

In gas turbine applications, DLN/DLE combustion is based on a concept of lean premixed combustion in which fuel is premixed with atmospheric nitrogen (from the combustion air) at the air-to-fuel ratio two times higher than the ideal stoichiometric level. Premixing gaseous fuel with combustion air before entering the combustor reduces peak flame temperature in the combustion zone, limiting thermal NOx formation. This lean premixed combustion process has now become the standard technique employed by gas turbine original equipment manufacturers (OEMs), particularly for natural gas and is referred to by a variety of trade names such as DLN (General Electric and Siemens-Westinghouse), DLE (Rolls-Royce), or SoLoNOx™ process (Solar® Turbines).

The premixing chamber must be specifically designed for every turbine and integrated into the turbine engine. Every four to five years, the combustion liners of the DLN/DLE combustors are deteriorated and must be replaced. When firing natural gas, most of the commercially available systems would guarantee a level of 9–25 ppmv NOx, dry range, depending on the manufacturer, turbine model, and application. Gas turbines fired with refinery gas typically have at least 10 percent greater amount of NOx emissions that natural gas fired turbines.

Water or Steam Injection

Water injection (WI) or steam injection (SI) is commonly used in the conventional gas turbine to quench the temperature down and reduces NOx to approximately 25 ppmv at 15 percent O_2, when operating on natural gas in 50–100 percent load range. Water injection provides greater NOx reduction than steam injection and corresponds to an approximate 70 to 80 percent reduction from uncontrolled levels for utility and large turbines operating on natural gas. However, water injection tends to increase carbon monoxide (CO) emissions considerably Application of water or steam injection in turbines has increased maintenance requirements due to erosion and wear. High purity water is used to minimize wear and fouling on turbine components (nozzles, combustor cans, turbine blades).

Great Southern Flameless Heater

Great Southern Flameless (GSF) Group developed a flameless furnace technology which accommodates all the required operational variances in a refinery heater while providing NOx emissions levels similar to that of an SCR. Because refinery heaters do not always operate at steady state, numerous design features were addressed in the GSF's flameless heater technology named "Flameless Nozzles Grouping (FNG)." Key features include:

- SCR level NOx emissions without traditional combustion with an SCR. Based on the GSF vendors, between 4 and 8 ppmv NOx can be achieved on refinery fuel gas;
- No flame or gas impingement due to patented castable refractory dimple pattern pins rotating flue gas to the wall;
- No hazardous by-products or ammonia slip and improved reliability; and
- Easy scale-up available to any required process heater size.

FNG is a technology that requires heater replacement and retrofit options are currently under development. Flameless combustion technology was applied for the first time to process heaters at Coffeyville refinery in Kansas (capacity: ~3,500 barrels per day (bpd)) in 2013. There is no current data available for large refinery applications (e.g., greater than 90,000 bpd).

ClearSign Core™ Burner

ClearSign Combustion Corporation has developed DUPLEX™ Technology, a new technology for reducing NOx emissions from fired heaters and boilers. The DUPLEX™ technology involves the installation of a porous ceramic surface where combustion is sustained. The combustion occurs inside the pores of this ceramic tile, resulting in reduced flame height and improved heat radiation. The premixing of air, fuel, and entrained flue gas prior to combustion at the duplex ceramic surface allows the combustion to occur at lower temperatures and lower reaction time which reduces thermal NOx formation. The combustion is contained within the porous ceramic surface, thus minimizing tube damage that can result from flame impingement. Flame impingement is one of the safety concerns that were raised by refinery stakeholders as the reason why traditional ULNB may not be an option. The ceramic surface also increases the overall heater efficiency due to improved radiation properties of the DUPLEX™ surface when compared to traditional ULNB.

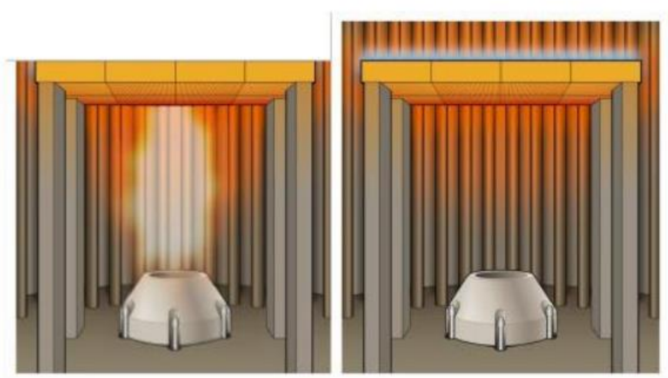

Figure A-2. Conventional burner heating up a DUPLEX tile

ClearSign Core™ process burners are the latest advancement and redesign of the DUPLEX™ technology. The redesigned ClearSign Core introduces a new pilot which simplifies the structure and operation of the burner. Adding the pilot eliminated the need of a transition burner which improves stability, turndown, and size making the redesigned core a direct replacement for traditional ULNB. The flame is compact and less sensitive to heat density and burner spacing limitations commonly encountered with traditional ULNB offerings. This is ideal for existing process heaters where current generation ultra-low NOx burners are not suitable due to the arrangement of the burner and combustion surfaces. Conventional ULNBs typically operate 15 to 40 ppmv under ideal conditions and can be as high as 50 ppmv in some cases where burner spacing is not optimal. ULNBs encounter flame shape issues whereas the ClearSign™ core technology has the capability to achieve sub-5 ppmv NOx corrected to 3% O_2. The core technology is capable of a 5:1 turndown ratio and achieve sub-30 ppmv CO throughout the turndown. In addition, the technology does not have tip plugging or fouling issues commonly associated with traditional ULNB.

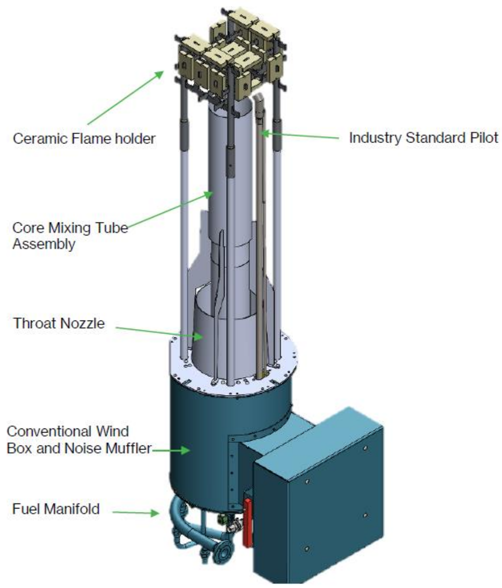

Figure A-3. ClearSign Core Process Burner

There is currently a demonstration project of the ClearSign Core™ process burner within the District located at World Oil. The BACT demonstration project is conducted in partnership with ClearSign, World Oil, and South Coast AQMD to demonstrate the capabilities of these latest generation ClearSign burners. As of March 2021, the ClearSign Core™ burners have been installed and operating in a five burner, 39 MMBtu/hr vertical cylindrical heater. Near full firing rate has been achieved with all 5 burners operating. Field installations of the technology so far have demonstrated safe, reliable performance with NOx levels at 29.3 ppmv corrected to 3 percent oxygen. Burners are currently operating with some modifications resulting in higher than expected NOx performance. The replacement components are being fabricated for installation in 2022. Once the replacement components are installed, ClearSign anticipates sub-5 ppmv performance on natural gas.

On August 12, 2020, ClearSign announced their partnership with Zeeco, a worldwide leader in design and manufacturer of advanced combustion controls. The agreement will increase manufacturing, product development, and performance testing of the ClearSign technology which has the potential for widespread use by refiners and other users. The technology has been installed many locations and applications such as once-through-steam-generators, process heaters, and flares and has demonstrated low NOx emissions levels in stable, safe operation with firing rates ranging from 6 to 60 MMBtu/hr.

John Zink Hamworthy SOLEX™ Burner[1]

John Zink Hamworthy presented information regarding the SOLEX™ technology at Working Group Meeting #9 on December 12,2019. SOLEX™ is a next generation ULNB technology that is currently in development which can achieve 5 ppmv NOx emissions regardless of fuel composition and furnace temperature, making this ideal for applications using refinery fuel gas. The composition and higher heating value (HHV) of refinery fuel gas can vary, potentially lead to higher NOx emissions. The burner is designed with two significant combustion zones to achieve this emissions level from startup to full capacity with near-zero CO emissions. In addition, the SOLEX™ burner's compact flame lengths solve many issues ultra-low NOx burner technologies face in the market today such a long flame that can lead to flame impingement of process tubes. Achieving 5 ppmv NOx emissions has traditionally required flue gas treatment solutions such as Selective Catalytic Reduction (SCR) systems. The SOLEX™ burner delivers similar NOx emissions and performance using proven combustion method and is capable of being wall, floor, or roof mounted making in applicable in various heater types. The performance for each of the categories are summarized here:

- NOx emissions
  - Can replace the need for SCR or other NOx reducing technology
  - Independent of fuel compositions >75% H_2, air preheat, furnace temperature, operation range, and firebox heat density
  - High predictability and repeatability
- CO emissions
  - Decoupled from cold furnace temperatures
  - Near-zero CO emissions at startup and turndown conditions
- Flame
  - Lengths less than half of ultra-low NOx staged fuel burners
  - Solution for tight burner spacing arrangements
  - Round or flat flame options
- Retrofits
  - Fits traditional ultra-low NOx burner footprints
  - Up-fired, down-fired, and horizontally fired

To achieve the performance, the SOLEX™ burners requires advanced combustion control scheme along with a forced and an induced draft fan. John Zink is currently working on a commercial demonstration of the SOLEX™ burner with a facility within the District.

[1] John Zink Hamworthy SOLEX Burner at https://www.johnzinkhamworthy.com/wp-content/uploads/solex-burner.pdf. Accessed on July 10, 2020.

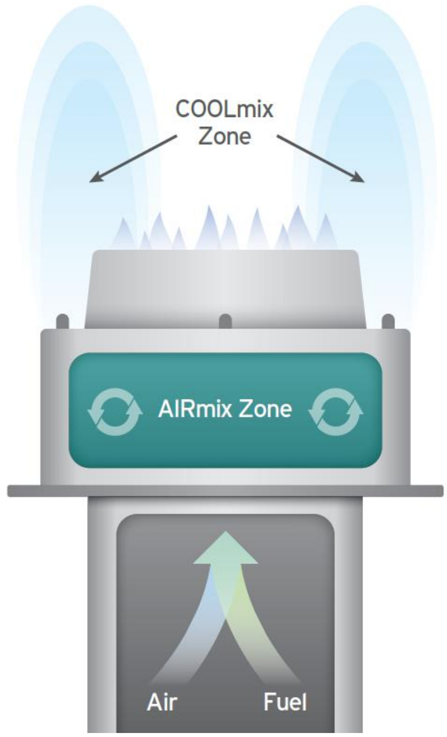

Figure A-4. John Zink SOLEX™ Burner

FLUE GAS TREATMENT TECHNIQUES

Selective Catalytic Reduction

SCR technology is a well-established and mature technology for controlling NOx emissions. SCR is a chemical process of using a reductant like ammonia (NH_3) to convert NOx in the flue gas into nitrogen (N_2) and water (H_2O) with the aid of a catalyst.

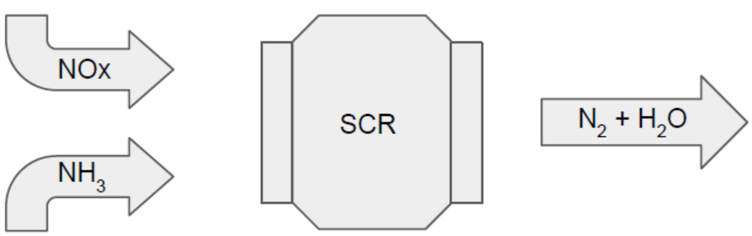

Figure A-5. NOx Reductions in SCR

Over the past three decades, SCR technology has been used successfully to control NOx emissions. The technology is considered mature and commercially available and can reduce up to 95 percent NOx emissions through the following reactions:

$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$ (Reaction 1)
$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O$ (Reaction 2)

It should be noted that, at temperature above 797°F, ammonia can be oxidized to form NO and N_2O which are undesirable reactions since NO and N_2O will ultimately convert to NOx and increase the NOx emissions.

$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O$ (Reaction 3)
$4NH_3 + 4NO + 3O_2 \rightarrow 4N_2O + 6H_2O$ (Reaction 4)

A successful SCR catalyst can facilitate the reduction of ammonia (Reactions 1 and 2) while subsiding the ammonia oxidation reactions (Reactions 3 and 4). Typically, the SCR catalysts are vanadium, titanium, and/or zeolite based, with different sizes, shapes, and operating temperatures. New generation of low temperature SCR catalyst can achieve 90 percent NOx reduction at temperatures lower than traditional catalyst. For example, Umicore's low-temperature catalyst, TripleCat DNX-LT (Figure 1) can achieve greater than 90 percent NOx reduction for the flue gas between 400° and 500°F.

Conventional SCR catalysts:	500°–800°F
Low temperature SCR catalysts:	300°–500°F
High temperature SCR catalysts:	800°–1,100°F

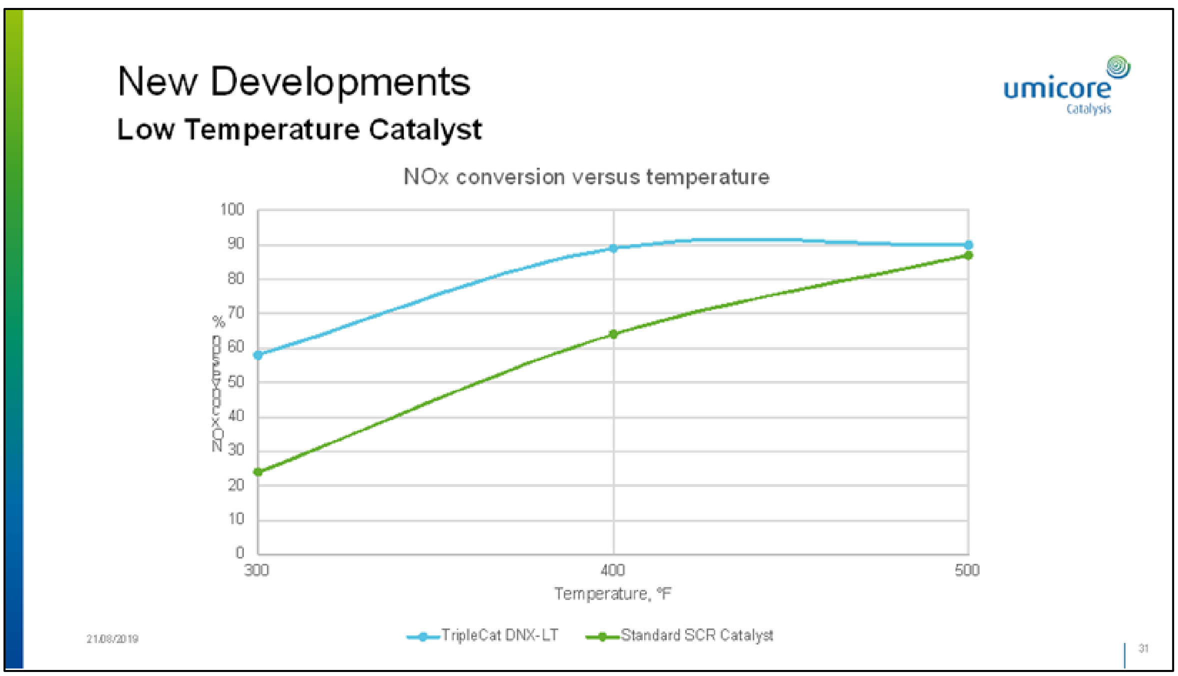

Figure A-6. Umicore's TripleCat DNX-LT

The stoichiometric amount of ammonia required is one mole of ammonia per mole of NOx reduced (NH_3/NOx = 1). Ammonia injection and mixing is critical since a non-uniform distribution and mixing can result in inadequate NOx reductions and/or lead to increased ammonia emissions (ammonia slip). Ammonia has the potential to form secondary pollutants (e.g., PM) in the atmosphere, especially if there are high concentrations of sulfur in the flue gas. To reduce the ammonia slip caused by imperfect ammonia distribution and mixing, SCR catalyst manufacturers have developed an ammonia slip catalyst, a layer of catalyst installed downstream of the SCR catalyst. Early generation of ammonia slip catalyst were based on precious metal which is highly active for ammonia oxidation. The new generation of ammonia slip catalyst offers the following advantages:

- Enhancing the selective reduction of NO to N_2 and supporting the oxidation of CO to CO_2 while suppressing the oxidation of ammonia to NOx;
- Allowing for operations at higher ammonia to NOx ratios to ensure complete NOx conversion;
- Maintaining low ammonia slips; and
- Reducing the overall SCR catalyst volume while maintaining the high NOx control efficiency.

However, SCR system designers and catalyst manufacturers will generally prefer to optimize the ammonia injection and distribution before recommending an ammonia slip catalyst, since the additional catalyst adds to the cost and requires additional space. Over the years, SCR system designers and catalyst manufacturers have enhanced their understanding of mixing and distribution of ammonia to achieve higher NOx removal efficiencies. Computational fluid dynamic modeling and cold flow modeling are utilized to help achieve uniform ammonia to NOx distribution and mixing in the SCR design phase to optimize SCR configuration and alleviate the need for an ammonia slip catalyst.

The South Coast AQMD requires the use of aqueous ammonia instead of anhydrous ammonia for SCRs due to safety concerns. In general, aqueous ammonia has lower risks and higher operating costs than anhydrous ammonia. A larger volume of aqueous ammonia is required to achieve the same NOx reduction, which increases delivery costs (e.g., delivering 29 percent aqueous ammonia includes the delivery costs of transporting the remaining 71 percent water). Aqueous ammonia also requires either compressed air for atomization or vaporizers to evaporate the water. The costs for operating with aqueous ammonia are approximately two times higher than the costs for operating with anhydrous ammonia.

LoTOx™ Application with Scrubber

LoTOx™ stands for "Low Temperature Oxidation" process where ozone is injected into the flue gas stream to oxidize insoluble NOx compounds into soluble NOx compounds. These soluble compounds can then be removed by various neutralization reagents (caustic solution, lime, or limestone) as well as the BELCO® regenerative LABSORB™ process.[2] LoTOx™ is a low temperature operating system in a range of 140°–325°F, while the optimal temperature is generally less than 300°F. The LoTOx™ is a registered trademark of Linde LLC (previously BOC Gases) and was later licensed to BELCO® of DuPont for refinery applications. An arrangement of LoTOx™ with EDV® scrubber is shown in Figure 2.

A typical combustion process produces about 95 percent NO and 5 percent NO_2. Both NO and NO_2 are relatively insoluble in aqueous solution, and thus a wet gas scrubber is inefficient in removing these insoluble compounds from the flue gas stream. However, with the injection of ozone into the flue gas stream, NO and NO_2 can be easily oxidized to highly soluble compounds (N_2O_5) (Reactions 5 and 6) and subsequently converted to nitric acid (HNO_3) in the wet scrubber (Reaction 7). The nitric acid is readily absorbed in aqueous scrubbing solution (Reaction 8) or by

[2] Edwin H. Weaver, Wet Scrubbing System Control Technology for Refineries - An Evaluation of Regenerative and Non-Regenerative Systems, Belco Technologies Corporation, Presented at the Refining China 2006 Conference, April 24-26, 2006, Beijing, China.

dry/semi-dry scrubber adsorbents such as limestone or lime (Reactions 9 and 10) and is removed from the wet scrubbers. In addition, ozone is highly selective for NOx relative to other combustion products such as SO_2 and CO and the rate of oxidizing reactions for NOx (Reactions 5 and 6) are faster compared to CO or SO_2 oxidation reaction (Reactions 11 and 12), and thus, the presence of SO_2 or CO does not impact NOx removal.

$NO + O_3 \rightarrow NO_2 + O_2$	(Reaction 5 – Fast)
$2NO_2 + O_3 \rightarrow N_2O_5 + O_2$	(Reaction 6 – Fast)
$N_2O_5 + H_2O \rightarrow 2HNO_3$	(Reaction 7 – Very Fast)
$HNO_3 + NaOH \rightarrow NaNO_3 + H_2O$	(Reaction 8)
$2HNO_3 + CaCO_3 \rightarrow Ca(NO_3)_2 + H_2O + CO_2$	(Reaction 9)
$2HNO_3 + CaOH \rightarrow Ca(NO_3)_2 + 2H_2O$	(Reaction 10)
$SO_2 + O_3 \rightarrow SO_3 + O_2$	(Reaction 11 – Very Slow)
$CO + O_3 \rightarrow CO_2 + O_2$	(Reaction 12 – Slow)

The LoTOx™ process requires oxygen supply for ozone generation. Unlike SCR technology which requires ammonia storage, the LoTOx™ technology modulates ozone generation on demand as required by the process. A ratio of NOx/O_3 of about 1.75–2.5 is needed to achieve 90–95% NOx conversion and reduction. The ozone that does not react with NOx in the LoTOx™ process is scavenged by sulfite in the scrubber solution and the ozone slip is in a range of zero to 3 ppmv.

Some advantages of LoTOx™ application in comparison to SCR are as follow:

- LoTOx™ does not require heat input to maintain operational efficiency and enables maximum heat recovery of high temperature combustion gases.
- LoTOx™ can be integrally connected to a wet (or semi-wet) scrubber and become a multi-component air pollution control system that can reduce NOx, SOx, and PM in one system whereas SCR is primarily designed to reduce only NOx.
- There is no ammonia slip, SO_3, and ammonium bisulfate issue associated with LoTOx™ application.

Potential drawbacks with LoTOx™ include:

- Significant amount of water is needed for the process, and it consequently generates waste effluent that requires an effluent treatment system. Thus, a water supply and effluent treatment system will need to be constructed to accommodate the LoTOx™ system.
- Since the LoTOx™ system requires high electrical power usage and oxygen demand, annual operating costs for the ozone generator could be potentially high.
- Nitrates in wastewater effluent may be a concern for treatment and/or discharge of the wastewater.

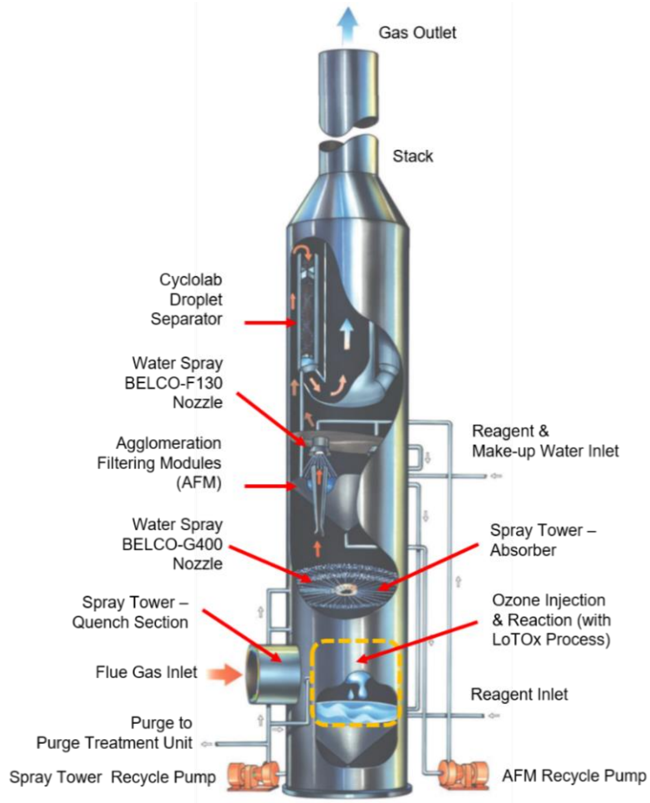

Figure A-7. EDV® Scrubber with LoTOx™ NOx Control[3]

There are more than fifty LoTOx™ systems installed for FCCUs, boilers, furnaces, and other combustion equipment since 1997, and more than two dozen applications with DuPont Clean Technologies' ("DuPont") BELCO® EDV® scrubbers since 2007. The table below contains a list of the LoTOx™ applications at refineries. The EDV® scrubber with LoTOx™ system has been in operation since February 2007 at a 52,000 barrels per day FCCU at Tesoro's Texas City Refinery and at a 12,500 barrels per day FCCU at HollyFrontier's Cheyenne Refinery in Wyoming since September 2015. Applications in FCCU in refineries met 8–20 ppmv NOx. According to the manufacturers[4], LoTOx™ can be designed to achieve 2 ppmv NOx from current inlet concentrations (85–95 percent control efficiency) for FCCUs. The table below list existing LoTOx™ installations.

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[3] BELCO® Wet Scrubbing Systems at https://www.dupont.com/content/dam/dupont/products-and-services/consulting-services-and-process-technologies/clean-technologies-and-technology-licensing/documents/DSP_%20BELCO_EDV_brochure_K24207.pdf. Accessed on September 5, 2019.

[4] Final Staff Report on Proposed Amendments to Regulation XX - NOx RECLAIM, South Coast AQMD December 4, 2015, page 60.

Table A-2. LoTOx™ Installations

No	Application	Exhaust Gas Flow (scfm)	NOx Inlet (ppmv)	NOx Outlet (ppmv)	% Control	Startup Date
1–5	Five FCCUs in the U.S.	40,000–260,000	70–120	8–20	80%	2007
6–7	Two sulfuric acid plants in the U.S.	16,800	90	10	90%	2008
8–18	Nine FCCUs and two LoTOx™ ready installation in the U.S.	12,000–310,000	30–250	10–18.5	93%	2008–2015
19–35	Ten FCCUs, a refinery boiler, six LoTOx™ ready installation in China	90,000–390,000	100–350	20–73	80%	2012–2015
36–37	FCCUs in Thailand & Romania	43,000–135,000	230–250	20–73	80%	2015–2019

UltraCat™ Application

UltraCat™ is a multi-component air pollution control technology developed by Tri-Mer. UltraCat™ ceramic catalyst filters are composed of ¾ inch thick fibrous ceramic tube walls embedded with proprietary catalysts throughout the wall. UltraCat™ can remove NOx, SO_2, PM, hydrogen chloride (HCl), dioxins, and metals such as hexavalent chromium and mercury. The ceramic filters are self-supporting meaning they do not require filter cages and are described as having a service life of five to ten years. SOx and acid gases are controlled via dry sorbent injection upstream of the ammonia injection. The optimal operating temperatures for PM and NOx control are approximately 300°F to 750°F. Aqueous ammonia injected upstream of the catalytic filters is used to remove NOx; removal efficiency is about 70 percent starting at 350°F and improves to over 90 percent between 400°F and 800°F. Less than 5 ppmv of ammonia slip can be achieved. A NOx removal efficiency of greater than 95 percent is achievable in certain applications. Dry sorbent such as hydrated lime (sodium bicarbonate) injected upstream of the catalytic filters is used to remove SO_2, HCl, and other acid gases with a removal efficiency of 90 to 98 percent. Particulate control is reported to a level of 0.001 grains/dcsf (2.0 mg/Nm^3) regardless of inlet loading. In addition, mercury control is also possible. UltraCat™ filters are arranged in a baghouse configuration with low pressure drop (about 5 inches water column), and it has a reverse pulse-jet cleaning action (the filters are back flushed with air and inert gas to dislodge the particulate deposited on the outside of the filter tubes). The UltraCat™ catalytic filtering system is depicted in the figure below.

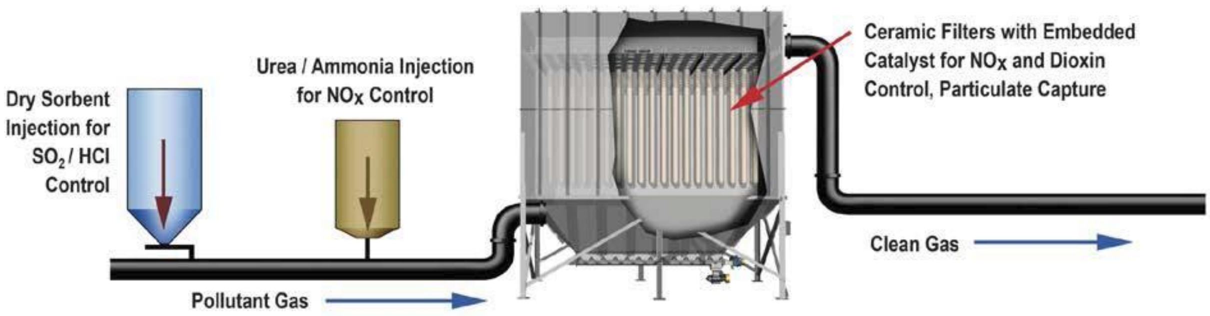


Figure A-8. UltraCat Filters

The technology is modular and will allow for a phased approach using 20 percent of the total flow as an opportunity to demonstrate actual capability of the technology. Tri-Mer stated that they can retrofit the currently existing baghouse to the UltraCat™ technology which will minimize downtime and space constraints of the facility.

APPENDIX B BOILERS AND PROCESS HEATERS

Process Heaters and Boilers

The largest category of equipment subject to PR 1109.1 is the boilers and process heaters category which represents the largest NOx emission sources at refineries and related industries. Over 60 percent of all emissions from equipment subject to PR 1109.1 is attributable to process heaters and boilers. Process heaters are indirect-fired heaters designed to supply the heat necessary to raise the temperature of feedstock to the distillation or reaction levels. Boilers are combustion sources used to generate the steam necessary for plant operations. Steam is primarily used for heating, separating hydrocarbon streams, hydrogen production, stripping medium, and producing electricity by expansion through a turbine. The design and arrangement of a fired process heater is different from that of a fired boiler, so the challenges associated with installing NOx controls may be different. For example, in a boiler, the number and size of a burner is different from that of a process heater, and it does not typically encounter the firebox size and spacing constraints like those found in some process heaters. However, boilers and process heaters are similar in that they are both combustion devices which burns fuel and most control technologies developed for controlling NOx emissions are applicable to both.

Due to the variety of boilers and process heaters, the units were segregated into six major subcategories prior to conducting the BARCT assessment as shown in the figure below.

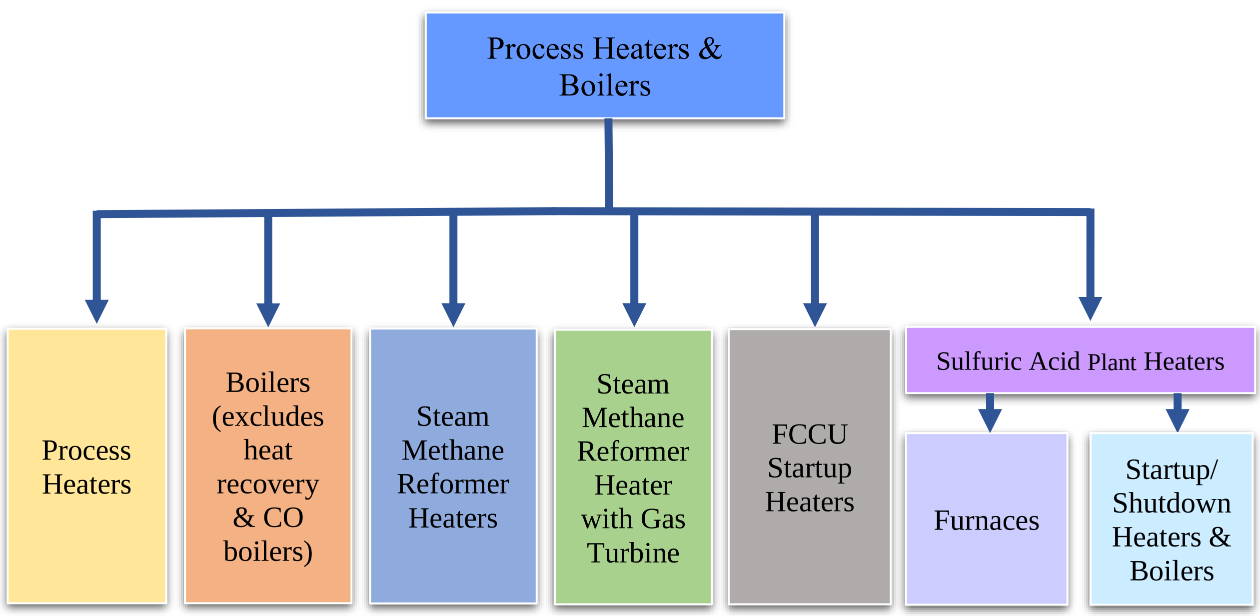


Figure B-1. Six major sub-categories of Boilers & Process Heaters Category

Each of the large boiler and process heater subcategories were divided into smaller categories based on size or maximum rated heat input in order to conduct a more granular BARCT assessment. Equipment was also grouped into subcategories to reflect the applicable technology control options. Staff divided the boilers and heaters into four categories as described in the table below.

Table B-1. Boiler and Heater Size Categories

Heaters and Boilers Size Categories
< 20 MMBtu/hr
≥20 to <40 MMBtu/hr
≥40 to ≤110 MMBtu/hr
>110 MMBtu/hr

Process Heaters

Process heaters are indirect-fired heaters designed to supply the heat necessary to raise the temperature of feedstock to the distillation or reaction levels. In a fired process heater, fuel and air are combusted in a firebox to produce heat that is transferred to process tubes containing process fluid. Process heaters are used in various processing units throughout the refining industry and have many applications – heaters are specialized based on their processing unit location and application. Examples of specialized applications include steam methane reformer (SMR) heaters located in hydrogen plants and sulfuric acid furnaces located in sulfuric acid plants, each are designed for different purposes, and each will combust different fuel types. The fuel burned in an SMR heater may be refinery gas, natural gas, pressure swing adsorption (PSA) off-gas or a combination of these fuels. The combustion fuel in a sulfuric acid furnace can consist of sulfur, natural gas, refinery gas, and hydrogen sulfide. The size and number of burners will also vary greatly. An SMR heater can potentially have over 350 small burners whereas a sulfuric acid furnace will have two large burners. Each burner type will have different design requirements for the intended application and different associated costs.

Boilers

Boilers are combustion sources used to generate the steam necessary for plant operations. A boiler converts water into steam through combusting and converting a fuel into heat which is transferred to the contained water and ultimately is converted to steam. Steam is an integral part of refinery or industrial operations and is primarily used for heating, separating hydrocarbon streams, hydrogen production, stripping medium, and produce electricity by expansion through a turbine.

There are two main categories of boilers:

- Fire Tube Boilers – consist of a system of tubes through which the heat source passes. The tube containing the heat source is surrounded by water which gets heated as the tube temperature rises. Eventually, the water is converted to steam and gets released.
- Water Tube Boilers – in contrast to fire tube boilers, these boilers consist of a series of water-containing tubes surrounded and heated by hot combustion gases. This is the most common type of large boilers found in refinery applications because very high pressures can be obtained.

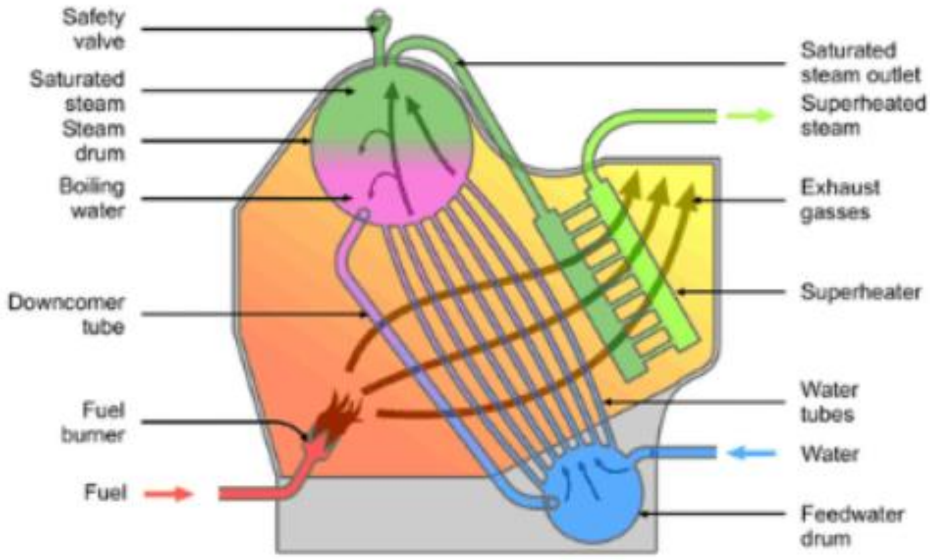


Figure B-2. Water Tube Boiler

Two other types of boilers used for steam generation are heat recovery boilers and carbon monoxide (CO) boilers. Heat recovery boilers are excluded from the boiler category since they are unfired units that do not generate any NOx emissions. There is one CO boiler located in the South Coast Air District which is currently unfired and operated as a heat recovery device used for steam generation. However, the CO boiler is equipped with LNB and capable of firing. If the CO boiler fires and becomes a combustion source, the emissions will be aggregated with the emissions from the FCC unit and will be subject to the NOx limit for the FCCU category.

The other type of unfired heat recovery boilers is used in the exhaust section of a gas turbine and commonly known as a heat recovery steam generator (HRSG). These types of boilers recover heat from the exhaust of a gas turbine to produce low, medium, and high-pressure steam. Another category of unfired boilers is waste heat boilers which similarly recover heat from process flue gas streams to generate steam. These types of units are generally located downstream of furnaces or heaters and can be found throughout the facilities such as coke calciner, sulfuric acid plants, hydrogen production plants and sulfur recovery plants. These types of unfired units have no combustion source and hence no NOx emissions.

Steam Methane Reformer Heaters

Steam methane reformers are specialized process heaters used in hydrogen production. SMR heaters burn fuel (PSA off-gas, natural gas, or refinery gas) to generate heat for the endothermic reforming reaction of hydrocarbon and steam over a nickel-based catalyst. As a result, SMR heaters typically operate at a higher temperature than traditional process heaters (2,100 °F) which has the potential for higher NOx emissions. The burner arrangement is also unique in SMR heaters. They can be either down-fired or side-fired and the number of burners can be over 350 burners in some cases.

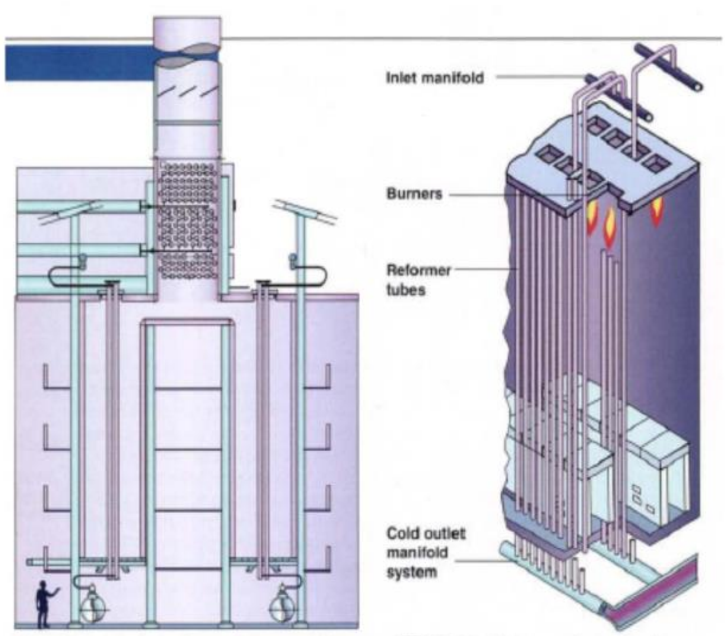


Figure B-3. Typical reformer heater designs can potentially have over 300 burners. All are greater than 110 MMBtu/hr in size

Steam Methane Reformer Heater with Integrated Gas Turbine

There is a special case arrangement where an SMR heater is integrated with a gas turbine. There is one refinery subject to PR 1109.1 where this arrangement exists and therefore, this unit has been segregated into its own subcategory. In a typical gas turbine, natural gas is fired in the gas turbine and the hot exhaust stream is normally sent to a HRSG, where the heat is recovered to generate steam – this is known as combined cycle operation. However, when an SMR heater is integrated with a gas turbine, part of the hot exhaust stream from the gas turbine replaces the furnace combustion air which increases thermal efficiency. This provides preheated air into the furnace, thus reducing the fuel demand to the SMR heater. This is typically referred to as integrated operation. For this arrangement, only a portion of the gas turbine exhaust is used as heater combustion air. The remaining gas turbine exhaust combines with the SMR heater exhaust prior to exiting the stack, as a result, the NOx emission is corrected to 15% and not 3% oxygen like a typical SMR heater. The SMR heater in this special arrangement is equipped with combination of NOx controls, LNB and SCR, which allows the unit to perform at less than 5 ppmv NOx at 15% oxygen.

FCCU Startup Heaters

Startup heaters or direct-fired air heaters are typically used in Fluidized Catalytic Cracking Units (FCCU) in petroleum refineries. These types of heaters are primarily used during startup operations to heat the catalyst bed in the regenerator section of the FCCU. Once the catalyst bed is heated up to the desired temperature or during normal operation, the heater is not fired and air flows directly through the regenerator through the air heater without being heated. These heaters are not often used – some are only used once every five years.

Sulfuric Acid Plant Startup Heaters and Boilers

There are two startup heaters and one start-up boiler located at sulfuric acid plants which are used as part of the startup cycle. The heaters are used for pre-heating the furnace and converter catalyst during cold startups after an extended maintenance outage. One facility has a startup boiler that provides steam when the main furnace is down – steam for the plant is primarily generated from the waste heat recovery boiler after the furnace.

Sulfuric Acid Furnaces

Sulfuric acid furnaces are another specialized subcategory of heaters that are utilized at sulfuric acid plants to produce sulfur dioxide gas which ultimately is converted into sulfuric acid. There are two sulfuric acid furnaces in PR 1109.1, and both are spent acid regeneration furnaces. These types of furnaces are primarily used for decomposition of spent sulfuric acid generated from the refinery's alkylation process. Feedstock or raw materials are from a variety of sulfur-containing streams and are fed into the furnace's combustion chamber. Depending on facility location, raw materials may include spent acid, hydrogen sulfide, liquid sulfur and hydrocarbon at various ratios. Hydrogen sulfide and sulfur both provide heating value when used as raw materials, however hydrogen sulfide has a much higher combustion heat than sulfur. This difference in the ratio of sulfur or hydrogen sulfide to spent acid affects fuel demand and NOx produced in the regeneration furnace.

BARCT Assessment

Assessment of South Coast AQMD Regulatory Requirements

As part of the BARCT assessment, staff reviewed existing South Coast AQMD regulatory requirements that affect NOx emissions for combustion equipment at petroleum refineries and facilities with related operations. The combustion equipment within the refining sector consists of seven main source categories. Staff evaluated NOx limits currently achieved in non-refinery settings for the purpose of technology transfer, source specific regulations, and regulations affecting specific equipment (e.g., boilers and heaters). NOx emissions from boilers and heaters are regulated under several rules, including Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional and Commercial Boilers, Steam Generators, and Process Heaters; and Regulation XX – Regional Clean Air Incentives Market (RECLAIM) (Regulation XX). The previously applicable NOx system-wide standards are listed in the following tables. Table B-1 summarizes regulatory NOx limits for the existing non-refinery boilers and heaters in the South Coast AQMD and Table B-2 lists the RECLAIM BARCT limits for refinery and non-refinery sector heaters and boilers. The RECLAIM BARCT limits established are not actual limits imposed one each individual unit, but an assumption of what of what each unit can do to meet the shave targets, thus actual limits that the unit may have to meet be higher than the BARCT limits determined in the assessment. RECLAIM offered facilities the flexibility to use RTCs from overcontrolling another unit or shutting down equipment.

Table B-2. South Coast AQMD NOx Rules and Limits for Heaters and Boilers

Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional and Commercial Boilers, Steam Generators, and Process Heaters	
Equipment Size	NOx Limit
>75 MMBtu/hr	5 ppmv
>25 but <75 MMBtu/hr	9 ppmv

Table B-3. South Coast AQMD RECLAIM NOx Assessments for Heaters and Boilers

Refinery Sector Limits and Assessments		
	2005 RECLAIM BARCT	**2015 RECLAIM BARCT**
Boilers and Heaters: <20 MMBtu/hr	12 ppmv	N/A
Boilers and Heaters: ≥20–<40 MMBtu/hr	9 ppmv	N/A
Boilers and Heaters: ≥40–≤110 MMBtu/hr	25 ppmv	2 ppmv at 3% O_2
Boilers and Heaters: > 110 MMBtu/hr	5 ppmv	
Non-Refinery Sector Limits and Assessments		
	2005 RECLAIM BARCT	**2015 RECLAIM BARCT**
Utility Boilers at Electric Power Generating Systems	7 ppmv	
Boilers	9–12 ppmv	No new BARCT
Heaters	60 ppmv	No new BARCT
Heat Treating Furnaces: > 150 MMBtu/hr	45 ppmv	9 ppmv at 3% O_2
Glass Melting Furnaces	1.2 lb/ton	80% reduction

Assessment of Other Regulatory Requirements

Regulatory requirements of South Coast AQMD and other air districts are compared to ensure that proposed limits under PR 1109.1 are not less stringent and to evaluate the current performance of similar units in similar industries. Other air districts' NOx rules and limits for heaters and boilers are shown in the following tables.

Table B-4. Bay Area Air Quality Management District

Bay Area Air Quality Management District	
Regulation 9-10-301	
Description	NOx Limit – Operating Day (ppmv*)
Refinery-Wide NOx limit for boilers, steam generators and process heaters, excluding CO Boilers	30

*Converted from lb/MMBtu

Table B-5. San Joaquin Valley APCD

Rule 4306 Boiler, Steam Generators, and Process Heaters – Phase 3				
Refinery Units (MMBtu/hr)	Operated on Gaseous Fuel		Operated on Liquid Fuel	
	NOx Limit (ppmv)	CO Limit (ppmv)	NOx Limit (ppmv)	CO Limit (ppmv)
5 to 65	30	400	40	400
65 to 110	25	400	40	400
>110	5	400	40	400

Assessment of Emission Limits of Existing Units

Most units within the process heaters and boilers category are currently regulated under RECLAIM and most units rated greater than 40 MMBtu/hr do not have any existing NOx permit limit. In contrast, most units rated less than 40 MMBtu/hr have NOx permit limits. Permit limits, source test data, and emissions data submitted to staff in the facility confidential surveys were analyzed to identify the emission levels being achieved with existing technology. Current and emerging technologies are assessed to determine the feasibility of achieving lower NOx emission levels. An initial BARCT emission limit is proposed based on the BARCT assessment. Costs are gathered and analyzed to determine the cost for a unit to meet the proposed initial NOx emission limit. Cost-effectiveness calculation considers the cost to meet the initial proposed NOx limit and the reductions that would occur from implementing a technology that could meet the proposed limit. A final BARCT emission limit is established based on the BARCT assessment, including the cost-effectiveness and incremental cost-effectiveness analysis.

Process Heaters

There is a total of 139 units in the process heater category and most units less than 40 MMBtu/hr currently have a NOx permit limit that ranges from 15 to 45 ppmv. Units larger than or equal to 40 MMBtu/hr typically do not have a permit limit, however units that have a NOx permit limit range from 5 to 9 ppmv. These lower NOx concentrations are usually achieved with the operation of post-combustion controls such as SCRs.

Boilers

There is a total of 28 boilers in this category. Most units less than 40 MMBtu/hr currently have a NOx permit limit ranging from 9 ppmv to 40 ppmv and are fueled by natural gas. Over half of the units larger than or equal to 40 MMBtu/hr, do not have a permit limit and no NOx control. Only 8 units currently have SCRs installed and their NOx permit limits range from 9 to 17 ppmv NOx.

Steam Methane Reformer Heaters

All 11 SMR heaters in PR1109.1 are large heaters that range in size from 146 to 931 MMBtu/hr for this subcategory. There is one special case located at one refinery where the SMR heater shares a combined stack with an auxiliary boiler. The boiler provides steam for the reforming process, but the SMR heater has a slightly higher firing duty than the boiler (145.97 MMBtu/hr vs. 139.5 MMBtu/hr). The SMR heater has a higher NOx potential so this special unit with a combine stack will qualify for the conditional limit of 7.5 ppmv – this unit is currently performing at 7.2 ppmv. Most of the SMR heaters in this category are currently equipped with NOx emissions control such as LNB and SCR – majority are performing at 5 ppmv or less at 3% oxygen.

Steam Methane Reformer Heaters with Gas Turbine

There is one refinery that operates an SMR heater with an integrated gas turbine and will be categorized as its own sub-category. The arrangement and operation are unique when compared to other SMR heaters. The SMR is equipped with LNB and SCR and currently meeting the proposed BARCT of 5 ppmv at 15% oxygen.

Startup Heaters

There are five heaters in this category and annual emissions from this category is 0.0029 tons per day based on 2017 annual emissions data. NOx controls for this category of heaters are not cost-effective at $1.7 MM per ton of NOx reduced and will have a low-use exemption. The startup heaters are associated with the FCCUs and only used during FCCU startups.

Sulfuric Acid Furnace

There are two furnaces in the category, and both have a heat input greater than 40 MMBtu/hr. Both furnaces operate below 30 ppmv NOx.

Startup Heaters and Boilers at Sulfuric Acid Plants

Each of the two Sulfuric acid plants have startup heaters. The startup heaters are used to heat up the catalytic converter during periods of unit startup. Only one facility has a startup boiler that is only operated when the facility is down for maintenance.

Table B-6. Emissions of Existing Units

Units	Size (MMBtu/hr)	Total 2017 NOx Emissions (tpd)	NOx in Exhaust Flue Gas @ 3% O_2 (ppmv)
Process Heaters	**5.5 to 550**	**5.06**	**1.7 to 134**
Boilers	**14.7 to 352**	**2.56**	**4.5 to 117**
SMR Heaters	**146 to 785**	**1.02**	**1.5 to 66**
SMR Heater with Gas Turbine	**316 to 931**	**0.08**	**4.4[(1)]**
Startup Heater	**26 to 165**	**0.003**	**11.2**
Sulfuric Acid Furnace	**73.6 to 150**	**0.10**	**23 to 28**
Startup Heaters and Boilers at Sulfuric Acid Plants	**15 to 50**	**0.001**	**29 to 94**

(1) Corrected to 15 percent oxygen

Assessment of Pollution Control Technologies

As part of the BARCT assessment, staff conducted a technology assessment to evaluate available NOx pollution control technologies for all categories. Staff reviewed facility provided survey data, CEMS data, scientific literature, vendor information, and strategies utilized in practice. Staff also met with technology manufacturers to evaluate the technical feasibility and current capabilities of the NOx controls. Staff also conducted 16 site visits to assess any potential challenges and cost impacts of implementing NOx controls. For the boilers and process heaters category, staff identified two major NOx technologies, ULNB/LNB and SCR. ULNB/LNB can be classified as combustion control and SCR as post-combustion control.

In most cases, post-combustion technologies may be utilized in conjunction with combustion control technologies to achieve maximum NOx reductions. Minimizing NOx formation at the source will in turn reduce the NOx inlet to the SCR. A well designed and engineered SCR can achieve up to 95% reduction efficiency and by employing both burner control and SCR, it will achieve the maximum degree of NOx reduction as required by BARCT.

Most of the process heaters in the category are equipped with first generation LNB. Advancements have been made over the last 30 years that have improved their performance. Newest generation of burner control will typically yield NOx in the 20 to 35 ppmv range with RFG. Based on compliance tests of recent ULNB installations at a local refinery, NOx can be in the low to mid 20 ppmv range. The latest SCR technology with proper engineering and design can achieve up to 95% removal efficiency – both based on recent permit applications at an existing refinery. One of the challenges of LNB/ULNB is that some heaters are not suitable for LNB/ULNB retrofits due to specific constraints of the heater such as firebox size and floor spacing, turndown requirements, and proximity to process tubes.

To assess performance of existing burner performance, staff evaluated existing heater performance for units with burner control only. The tables below summarize staff's findings for existing burners installed on process heaters.

Table B-7. Burner performance based on age using refinery gas

Burner Observations for Existing Heaters (Refinery Fuel Gas)	
Traditional Burners (Premix or Raw Gas)	Highest NOx (75 to 134 ppmv)
>25 years old (LNB/ULNB)	High NOx (60 to 80 ppmv)
<25 years old (LNB/ULNB)	Low NOx (20 to 47 ppmv)

Based on current data and information, older first generation LNB/ULNB installed in the 1980's or 90's, does not perform as well as newer generation LNB/ULNB. Meetings with burner manufacturers confirmed that recent generation designs have improved burner performance over the last 30 years.

Table B-8. Percentage of heater with existing burner control

Existing Heaters (Refinery Fuel Gas)		
Heater Size Category (MMBtu/hr)	Percent of Equipped with LNB/ULNB	NOx Range (ppmv)
<20	88%	20 to 40
≥20 to <40	90%	15 to 80
≥40 to ≤110	83%	17 to 70
>110	97%	22 to 70

Based on the information in the table above, many of the heaters are already equipped with burner control technology, and it is suggested that the LNB/ULNB in existing heaters are designed and installed in accordance with the American Petroleum Institute (API) 560 recommended guidelines for fired heater refinery service. Thus, retrofitting these existing burners to the latest generation LNB/ULNB should not require major modifications.

SCR technology achieves the highest NOx removal efficiency and is commercially available. The technology is proven and utilized throughout various industries for NOx control. Catalyst technology has advanced over the last 30 years and along with understanding of ammonia injection, tuning, mixing/distribution, it has greatly improved the performance of the system. Most SCR manufacturers will use CFD and Cold flow modeling to maximum mixing. Based on recent permit applications at one refinery, a 96% reduction efficiency can be achieved with a single layer.

Initial BARCT Emission Limit and Other Considerations

The recommendation for the BARCT NOx emission limits is established using information gathered from existing South Coast AQMD regulations, existing units permitted in South Coast AQMD, regulatory requirements for other air districts, and the technology assessment. Both retrofit and new installations are considered. Once the initial limits are established, a cost-effectiveness determination is made at that initial limit. If the initial limit is not cost-effective, an alternative limit may be recommended. Unique circumstances are taken under consideration to distinguish alternative limits or to create provisions in the rule to address equipment that would otherwise not be cost-effective. Based on conversations with technology vendors and recent installations, staff concluded that 2 ppmv NOx is achievable. Newer generation LNB/ULNB can achieve 30 to 40 ppmv NOx and if a properly designed SCR system is applied that can achieve 95% reduction, 2 ppmv is technically achievable.

Cost-Effectiveness and NOx Control Technology Cost

For process heaters and boilers category, staff determined that the most effective technologies for reducing NOx emissions is a combination of LNB/ULNB and SCR. This is based on the concept that reducing the NOx at the point of generation will reduce NOx inlet into the SCR, thus a lower NOx in the SCR outlet. These two technologies when engineered and designed properly can achieve 2 ppmv NOx. In order to estimate total installation costs (TIC) for a SCR, staff used the U.S. EPA SCR cost spreadsheet. The spreadsheet uses input parameters to generate an estimated TIC. TIC is then used to calculate the cost-effectiveness using the DCF method described previously. However, one limitation to U.S. EPA SCR cost spreadsheet is that it was originally designed and based on the electric power generating sector – gas turbines SCR installations. Total Installation Cost (TIC) for SCR installations in the refining sector can be up to 10 times more expensive due to the limited space within processing units; some facilities have performed elaborate SCR engineering designs to install their SCRs. As a result of space and engineering requirements, TIC cost that a refinery incurs increases significantly compared to the electric power generating sector. To reflect the actual TIC of SCR installations in the refinery sector, staff modified the U.S. EPA SCR cost spreadsheet using actual TIC estimates provided by the facilities. Staff consulted with U.S. EPA Air Economics Group regarding staff's proposed methodology for revision of the SCR cost spreadsheet. Staff's revised methodology was approved and endorsed to reflect the change for the refinery sector.

Staff received two series of costs data submitted by facilities, in 2018 and 2021. The first cost data submission in 2018 by facilities consisted of data for 80 SCR projects, however staff excluded any provided costs that were for SCR catalyst replacements only – typical SCR catalyst requires replacement every 4 to 5 years and is considered an operation and maintenance (O&M) cost. The costs in the first submission were a mix of conceptual design cost estimates (+/- 50% accuracy) and detailed engineering cost estimates (+/- 10 accuracy) for projects due to the 2015 RECLAIM NOx shave. Staff assumed all costs received from facilities included capital, engineering, construction, tax, and shipping. In addition, all submitted costs were assumed to include increased labor costs associated with Senate Bill (SB) 54 which requires refineries to use unionized construction labor. Provided TCI costs were in different years, and therefore, staff escalated all cost at 4% inflation to 2018-dollar year to ensure costs were equivalent to one another. Below is the distribution of cost received based on equipment size.

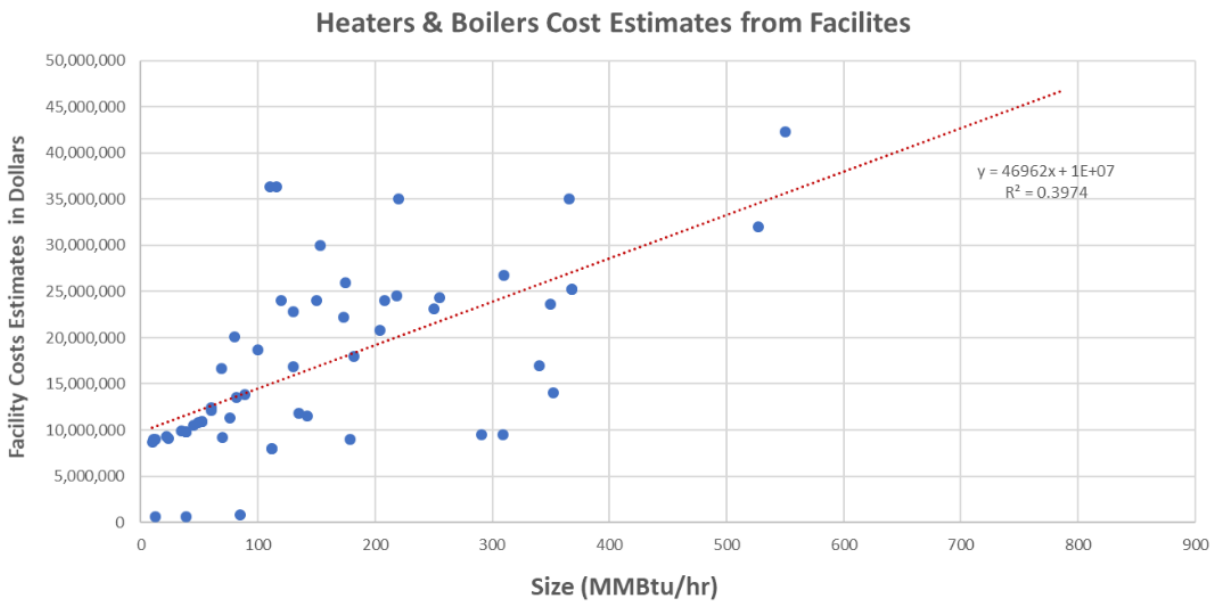


Figure B-4. SCR TIC costs provided by facilities versus corresponding heater/boiler sizes

Consistent with the methodology used in U.S. EPA cost spreadsheet, staff used the cost data provided to generate a cost curve below by dividing the TCI by the heater size to determine a cost per MMBtu/hr. Once the cost curve was generated, the curve equation was used to revise the total capital investment equation used in the U.S. EPA SCR cost spreadsheet. The equation and cost calculation used in the U.S. EPA SCR cost spreadsheet is based on the 0.6 power factor rule or "Rule of Six-tenths". Staff reached out to U.S. EPA Air Economics Group, Office of Air Quality Planning and Standards (OAQPS) regarding staff's proposed revision to the SCR model; the methodology proposed by staff to come up with a suitable TCI equation was endorsed. Staff discussed the methodology of revising the spreadsheet in Working Group Meeting #8 on June 27, 2019 and Working Group Meeting #9 on December 12, 2019. The SCR spreadsheet was used to estimate SCR cost for units where costs were not submitted or provided to staff. If the facilities provided cost for a unit, staff used the provided costs in the cost-effectiveness calculation. Some costs were provided for multiple heaters venting to a common SCR. For these heaters, staff summed the heat input for all heaters and divided the sum by the total cost for the SCR. Using the Rule of sixth tenths or 0.6 power factor rule (below), a cost for a project can be estimated based on a known cost. This methodology forms the basis of the U.S. EPA SCR cost model that was used to estimate cost for SCR projects at refineries.

$$C_B = C_A \left(\frac{S_B}{S_A} \right)^N$$

C_B = approximate cost of equipment having size S_B (MMBtu/hr, hp, scfm, etc.)

C_A = known cost($) of equipment having corresponding size S_A (same units as S_B)

(S_B/S_A) = ratio size factor

N = size exponent (varies 0.3 to >1.0, but average is 0.6)

Figure B-5. Rule of Six-tenths (0.6 Power Factor Rule)

The Rule of Six-tenths or 0.6 power factor rule is an equipment cost estimating method to determine an order of magnitude estimate, study estimate, or preliminary estimate and serves as a cost indicator at an early stage of the design. The rule of six tenths is not meant to be a definitive or detailed estimate of a project, those are major undertakings that require conducting a detailed engineering study and obtaining formal quotes and competitive bids from vendors for the project scope. The rule of six tenths is a ratio and proportion estimating method; ratio assumes that the relationship between the two things such as quantity, size, or amount. Proportion assumes that the two items are similar only differing in magnitude. Using the Rule of Six-tenths, approximate costs can be obtained if the cost of a similar item of different size or capacity is known. As part of the revised cost estimates provided to staff, the facilities provided some costs for actual SCR projects that are nearing completion or currently in the constructions phase – these were detailed estimates and provided an indication of a typical cost for a SCR project. However, majority of the cost were a mixture of project scope or order of magnitude cost estimate but based on Norton Engineering's review of the cost data provided to staff, the cost data were considered acceptable and reasonable considering potential complexities of SCR installations.

Once staff separate SCR projects, ULNB/LNB projects, and other post-combustion projects, staff proceeded to determine the "N" exponent that is more representative of the actual cost data provided. The "N" exponent is the size factor used to ratio and estimate cost from a known cost. The size factor exponent will vary from 0.3 to 1, but on average is near 0.6, hence the six-tenth or 0.6 power factor rule. In order to determine the "N" exponent, staff plotted the cost data and generated a power curve with all the cost data for a specific NOx control (Figure B-5 and B-6). From the power curve, an equation was obtained and the exponent in the equation is the "N" exponent used to revise the EPA SCR cost model that will be used to estimate SCR costs. The equation generated from the ULNB/LNB cost curve will be used to estimate burner costs.

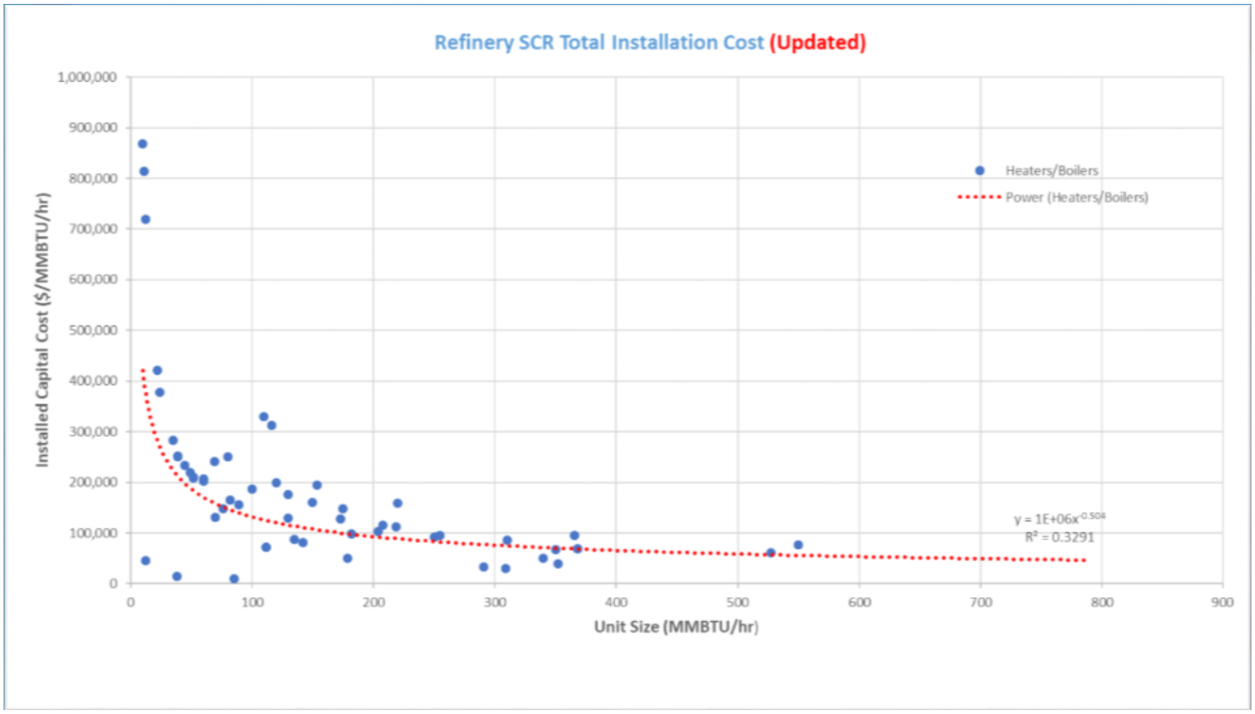


Figure B-6. Cost curve used to revise U.S. EPA SCR cost spreadsheet

Staff's initial assessment concluded that a combination of LNB and SCR can achieve 2 ppmv. Staff also concluded that since 90% of existing heaters currently have LNB or ULNB installed, there should not be any major issues to upgrade to newer generation burner technology. Upgraded burners will reduce inlet NOx emissions to the SCR and will yield between 30 to 40 ppmv NOx in heater applications. Staff concluded that burner control is feasible for most units and when applied in combination with a properly engineered SCR, it can achieve 92% or greater reduction, and thus, 2 ppmv is technically feasible. Staff added the additional cost of burner control to those units that required greater than 92% reduction efficiency.

For the cost of burner control , staff used a similar approach to estimate the cost of SCRs. As part of the first cost data submittal, staff requested TIC from facilities for existing LNB/ULNB projects. Facilities provided cost estimates for 13 installations and cost estimates ranged from $1.6MM to $9.8 MM. Costs were divided by unit size and plotted as a power curve. Figure B-6 demonstrates the curve that was generated and used to estimate burner control costs for a typical process heater and boiler application.

Burner controls for SMR heater applications are slightly different in design from that of a traditional process heater or boiler. SMR heaters operate at a higher temperature than a typical process heater and fuel can potentially contain up to 30% hydrogen (PSA-off gas) which will typically yield higher NOx at the burners. NOx can range from 40 to 50 ppmv, thus staff concluded that a 5 ppmv NOx limit is appropriate for the SMR heater category when SCR is applied as a NOX control option. In addition, SMR heaters typically have a larger number of burners when compared to a traditional process heater, so TIC will be higher.

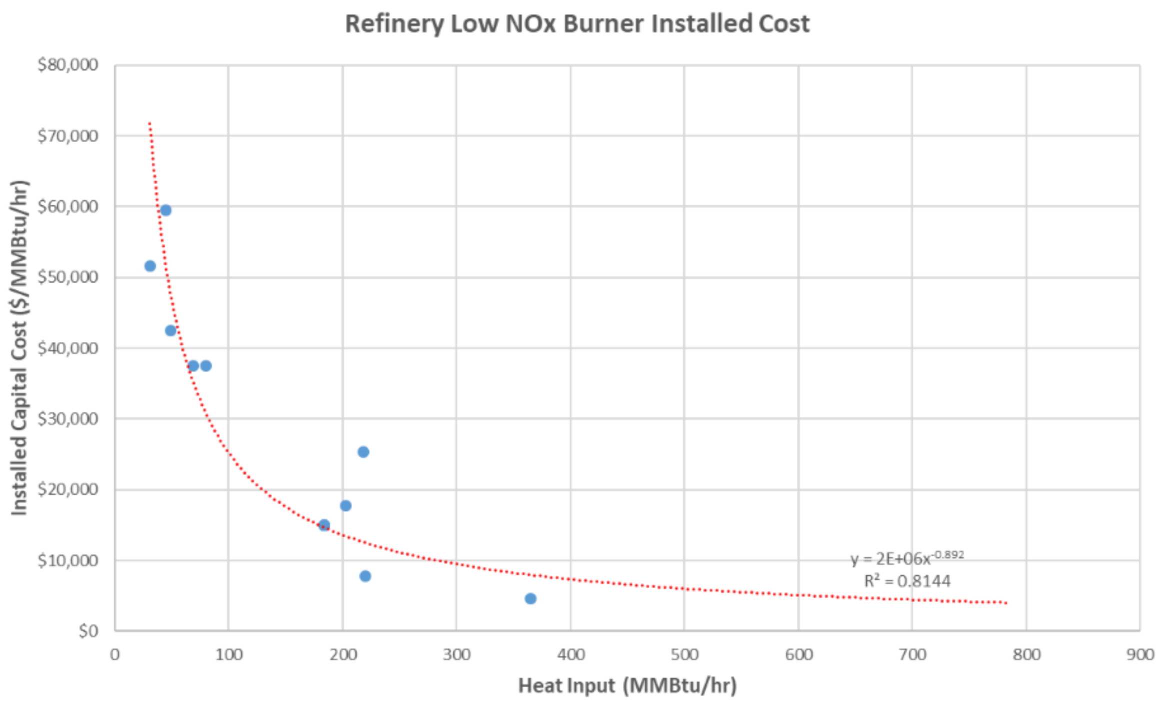


Figure B-7. LNB/ULNB Cost-Curve Used to Estimate Burner TIC For Boilers and Process Heaters

Staff generated the cost curve in Figure B-7 based on the cost estimates provided by facilities and meeting with burner manufacturers that specialize in SMR heater applications. The manufacturers stated that typical costs for an SMR heater LNB retrofit are typically twice the cost of traditional process heater LNB retrofit, so staff made the adjustments in Figure B-7 to reflect those costs. Figure B-7 shows the cost curve generated for a traditional refinery process heater versus a SMR heater and it shows that staff's overall cost estimates for a SMR LNB retrofit application will typically be twice as much as a traditional process heater application. The cost curve was used to generate cost estimates for units requiring LNB retrofits for SMR heaters – units that require greater than 92% reduction. However, since most of the heaters in the SMR category are currently equipped with some form of NOx control or LNB, staff anticipates that most of them will only require an SCR upgrade. For the cost of an SCR upgrade, staff estimated the cost to be 25% of a completely new SCR retrofit and assumed a 10 percent increase in O&M to account for increased cost of catalyst replacement, reagent usage, and electricity. This cost assumption for an SCR was also applied to all process heaters and boilers that require an SCR upgrade to meet the proposed BARCT. Staff used the modified U.S. EPA SCR cost model to generate a cost and then used 25% of cost generated for SCR upgrade costs. However, based on comments received from Norton Engineering, staff updated the SCR upgrade cost estimates. Staff initially estimated that the costs for a SCR upgrade would range between $4 MM to $7.1 MM but updated the range to $7.5MM to $10MM based on Norton Engineering's suggestion. Staff updated the cost-effectiveness for SMR category based on the new cost estimates.

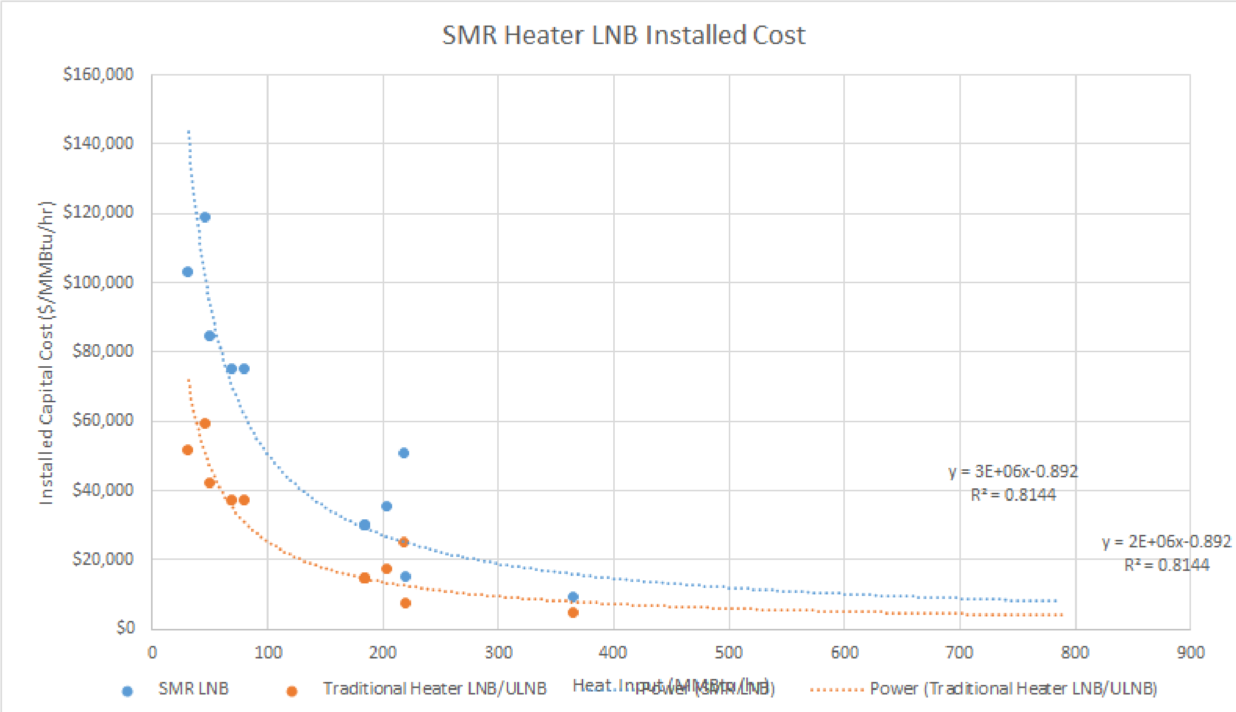


Figure B-8. LNB cost curve for SMR heaters versus traditional heaters

Once staff established the cost estimate methodology that was representative of the refining industry, staff proceeded with the cost-effectiveness analysis. Staff conducted separate cost-effectiveness analysis for the boiler and process heaters categories. For both cost-effectiveness analyses, if a facility provided cost estimates for a specific unit, staff used that cost. Staff only applied the previously outlined cost estimate methodology if the cost for a unit was not provided – approximately 75% of the cost used in the analysis were provided by facilities. The first or initial cost effectiveness analysis was based on the first cost data submission and the second cost-effectiveness analysis is based on the second cost data submission in March 2021.

Initial Cost-Effectiveness for Boiler and Process Heater Category

Based on the first cost data submission, staff presented the initial BARCT assessment for the process heaters and boilers in Working Group Meeting #9 on December 12, 2019, and a follow up in Working Group Meeting #10 on February 18, 2021. At WGM #9, staff established the 2017 as the baseline year for emissions. The 2017 baseline was established based on the most recent data available at the start of the rulemaking process. Furthermore, during discussions at Working Group Meeting #8 held on June 27, 2019, staff presented the methodology to calculate operational peak (maximum NOx concentration) for units that did not have a permit limit. The permit limit and operational peak were used to calculate cost-effectiveness for each category. Stakeholders expressed concern and requested that staff use annual average stack NOx concentration reported in the 2018 surveys as the basis for the cost-effectiveness calculation rather than the permit limits or operational peak proposed by staff. Stakeholders stated that it is more representative of unit operation and should be the basis for the cost-effectiveness calculation. Stakeholders expressed concern that use of permit limits or operational peak can potentially overestimate the emissions inventory and did not support using operational peak or permit limits for cost-effectiveness calculations. The tables below show the initial cost-effectiveness analysis based on the first cost submission for process heaters and boilers category.

Table B-9. Initial Cost-Effectiveness Assessment for Each Heater Class and Category

Heaters Cost-Effectiveness (First Cost Submission)				
	2 ppmv	**9 ppmv**	**30 ppmv**	**BARCT Limit (ppmv)**
Heaters (<20 MMBtu/hour)	$308,000	$212,421	$276,000	40/9
Heaters (≥20 - <40 MMBtu/hour)	$84,000	$78,000	$50,000	40/9
Heaters (≥40 - ≤110 MMBtu/hour)	$56,000	--	--	2
Heaters (>110 MMBtu/hour)	$40,000	--	--	2

Table B-10. Initial Cost-Effectiveness Assessment for Each Boiler Class and Category

Boilers Cost-Effectiveness (First Cost Submission)				
	2 ppmv	**5 ppmv**	**9 ppmv**	**BARCT Limit (ppmv)**
Boilers (<20 MMBtu/hour)	$94,000	$68,000	$56,000	40/5
Boilers (≥20 - <40 MMBtu/hour)	$512,000	$413,000	Achieved	40/5
Boilers (≥40 - ≤110 MMBtu/hour)	$50,000	--	--	2
Boilers (>110 MMBtu/hour)	$19,000	--	--	2

The initial cost-effectiveness analysis for boilers and process heaters determined that for units less than 40 MMBtu/hr it was not cost-effective to go to 2 ppmv, 5 ppmv, and 9 ppmv due to the low emission reductions. Staff proposed a BARCT limit of 40 ppmv since most units less than 40 MMBtu/hr are currently performing at or have permit limits near 40 ppmv; therefore, there will beno compliance cost for most of the units. Staff proposed a future BARCT limit of 9 ppmv for heaters and 5 ppmv for boilers once the current burners reach the end of their useful life or when 50% of the burners (heat input) is replaced. The facilities will incur some cost to upgrade the burners, but most of the cost will already be incurred due to end of useful life replacement. This assessment is based on emerging technology such as ClearSign™ and Solex™ from John Zink which can achieve single digit NOx emissions.

In a subsequent review of the process heaters, staff identified two process heaters within the less than 40 MMBtu/hour category that are currently performing above 40 ppmv. The NOx emissions for these two process heaters are approximately 58 ppmv and 96 ppmv with annual NOx emissions of 0.7 and 18.9 tons per year, respectively. These two heaters will incur compliance costs for retrofitting burner controls; burner cost estimates were from vendor quotes and revised burner cost-curve presented later in Figure B-13. Burner cost estimates were approximately $1.5 MM and $3 MM and based on the revised cost estimates, these two heaters are cost-effective to go to 40 ppmv or less. The cost-effectiveness is presented in Table B-11 below. An incremental cost-effectiveness analysis was not conducted since SCR was already determined not to be cost-effective for the less than 40 MMBtu/hour process heater category.

Table B-11. Cost-effectiveness for Process Heaters less than 40 MMBtu/hour Performing Higher than 40 ppmv

Process Heater Cost-Effectiveness for LNB/ULNB		
BARCT	**40 ppmv**	**Emission Reductions (tons per day)**
<40 MMBtu/hour	$16,000	0.031

Technical Feasibility of Proposed BARCT limit of 2 ppmv

Staff contracted two engineering consultants; Norton Engineering Consultants (NEC) and Fossil Energy Research Corporation (FERCo). Each consultant was tasked to conduct a separate independent analysis – Norton Engineering was tasked with the review of staff's BARCT assessment and FERCo was tasked with conducting site visits to assess the space constraint challenges with NOx control installations. The consultants' final assessment reports were released in December 2020 and both consultants presented their findings at Working Group Meeting #16 on December 10, 2020. The final reports supported staff's BARCT assessment conclusion that 2 ppmv is technically feasible for the process heaters and boilers greater than or equal to 40 MMBtu/hr category. ULNB when combined with SCR, can reduce the NOx inlet into the SCR which in turn will reduce the overall size of the SCR and related equipment such as reagent usage and catalyst quantity. Lower NOx inlet into the SCR will translate to a lower NOx outlet. Based on the Norton Engineering report, LNB/ULNB vendor guarantees are typically between the 20 to 50 ppmv NOx range for refinery fuel gas. Under sub-optimal conditions, the guaranteed levels typically fall in the 32 to 38 ppmv range. However, Norton Engineering did mention that on occasion, burner retrofit have been unable to achieve less than 50 ppmv. Stakeholders immediately expressed significant concern with the conclusions and the proposed BARCT limit of 2 ppmv by South Coast AQMD staff.

Refinery stakeholders questioned the technical feasibility of achieving 2 ppmv with ULNB and SCR combination despite the third-party engineering's support of staff's conclusions. Torrance refinery and Tesoro Refinery submitted comment letters regarding staff's conclusion. The Torrance refinery comments letter stated that there is not a "one-size-fits-all" technology that can guarantee same or similar results for all refinery process heaters and boilers in operation. Every unit should be evaluated on a case-by-case basis to determine a unit's ability to accept ULNBs. Retrofitting an ULNB is not as simple as pulling out the older burner and installing a new one.

There is much more that needs to be considered as part of the engineering and purchasing decision process. This can have an overall impact on the technical feasibility of achieving 2 ppmv. When considering or evaluating burner retrofit projects a facility must not only look at the burner, but also into other interrelated areas and current dynamics surrounding the existing process heater.

Marathon (Tesoro Refinery) in their comment letter submitted on February 1, 2021 provided information from an independent technical feasibility analysis that was conducted to address the proposed NOx emission limit by staff for refinery heaters greater than or equal to 40 MMBtu/hr. The comment letter included several attachments to substantiate the technical analysis. Comments centered around the key issues of technical feasibility, safety, and cost of NOx emissions controls for BARCT. The comment letter stated that South Coast AQMD's BARCT technology selection of ULNB and SCR for 2 ppmv are not technically feasible for most installations and presents unacceptable safety hazards on the broad universe of process heater designs within a refinery. Marathon (Tesoro Refinery) stated that there is inherent operational variability with refinery process heaters and staff's conclusions disregard the physical design characteristics that can impact safety and performance. The Tesoro Refinery letter highlighted concerns and feasibility of ULNB retrofit such as:

- Risk of flame impingement and safety
- Air preheater impact on ULNB performance
- Heater turndown and variable heat input operation
- Dynamic changes in fuel gas composition
- Physical features such as configuration, geometry, and firebox dimensions

The Marathon (Tesoro Refinery) comment letter also included a technical assessment of feasibility considerations for NOx emissions control retrofit which highlighted API and company specific standards for safe heater design, operation, and maintenance. The American Petroleum Institute (API) provides recommended guidelines for optimal operation of refinery fired heaters and burners in API 560 for fired heaters and API 535 for burners. The recommended guidelines include heat density and minimum burner spacing for optimal operation and safety, if any of these criteria are not meet, there can be an impact on actual NOx performance and operational safety, as described below:

- A higher heat density can result in higher flame temperatures and therefore increase NOx emissions.
- If burner spacing is not adequate, this can lead to flame interactions or coalescing which results in increased NOx emissions and potential impingement of tubes which can result in tube failures and lead to potential process safety issues.
- Not operating within these guidelines is considered "suboptimal" which can impact burner performance and safety.

Staff has acknowledged early in the rule development that not all heaters may be candidates for LNB/ULNB retrofits. In Working Group Meeting #6 held on January 31, 2019 staff presented the following discussion:

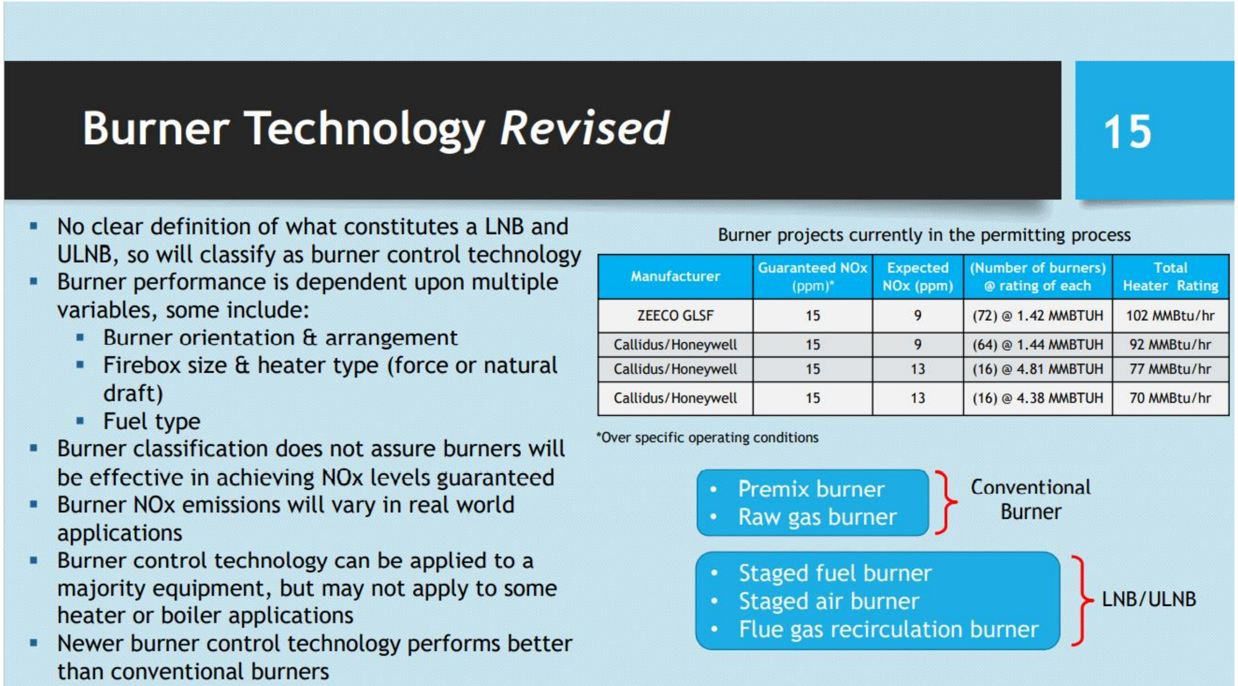


Figure B-9. Slide from Working Group #6

Norton Engineering's report further acknowledged that under optimal conditions, 30 ppmv NOx can be achieved with ULNB. However, under suboptimal installations, a burner will perform in the 40 to 50 ppmv range provided there is no potential for tube impingement. Based on stakeholder feedback regarding the challenges and installation of ULNB in older process heaters, staff consulted with Norton Engineering, FERCo, and SCR catalyst manufacturers regarding the feasibility issue raised by stakeholders. Consultants stated that regardless of ULNB NOx performance, 2 ppmv is feasible by installing multiple catalyst reactors with multiple ammonia injection grids (AIG) or static mixer in between each reactor. SCR catalyst manufacturers confirmed that these two stage reactor designs are used commercially in nitric acid plants where NOx emissions can be upwards of 4,000 ppmv and NOx removal efficiencies from this state-of-the-art design are 98% or greater. This alternative two stage SCR design was presented and discussed at working group meeting #17. Staff re-assessed the cost-effectiveness for a dual stage SCR based on the following assumptions:

Table B-12. SCR Cost Reassessment from Working Group Meeting #17

SCR Cost Effectiveness Reassessment		
SCR Design Parameter	Cost Increase	Comments
Catalyst Increase	30% of Catalyst Cost	Addresses the potential need of additional catalyst
Multiple Stage Reactor with additional AIG or Static Mixer	25% of Total Installed Cost (TIC)	Addresses potential cost increase of additional catalyst, reactor, and installation
Increase O&M	25% of O&M	Addresses potential increase in ammonia consumption and electricity needed for larger fan associated with multiple beds of reactors
Annual Tuning	Additional $40k added to annual O&M costs	Addresses the proper mixing and distribution

For all process heaters and boilers requiring greater than 92% NOx reduction, staff removed the cost of ULNB and replaced the cost for a second stage reactor arrangement based on the re-assessment assumptions above. The reassessment of the cost-effectiveness for the alternative pathway that uses a dual stage reactor SCR to achieve 2 ppm is shown below; it was still cost-effective to achieve 2 ppmv with a dual stage SCR reactor arrangement.

Table B-13. Cost-Effectiveness Reassessment Using Dual Stage Reactor

Equipment Class	NOx Limit	UNLB/SCR	Dual Reactor
Heaters 40 – 110 MMBtu/hr	2 ppmv	$35,000	$39,000
Heaters > 110 MMBtu/hr	2 ppmv	$35,000	$44,000
Boilers 40 – 110 MMBtu/hr	2 ppmv	$49,000	$48,000
Boilers > 110 MMBtu/hr	2 ppmv	$12,000	$15,000

Refinery stakeholders immediately raised the concern that staff did not consider space availability and constraints for this type of design. Refineries cannot accommodate a second SCR reactor which makes the alternative pathway not technically feasible. In addition, stakeholders stated that staff underestimated costs for a two-stage arrangement; cost for this design can be 80% more than a typical single reactor SCR. In response to stakeholder concerns, staff concluded that a higher NOx limit of 5 ppmv will likely address those concerns. For most devices in the process heater and boiler category, a 5 ppmv NOx limit will only require a single reactor SCR system and 5 ppmv NOx limit has been demonstrated with several units already meeting the limit. A NOx limit of 5 ppmv would achieve 90 percent of the estimated NOx reductions of 2 ppmv. A 5 ppmv NOx limit will also alleviate the concerns and challenges of utilizing a ULNB.

Revised Cost-Effectiveness Based on Second Cost Data Submission

At the February 2021 Stationary Source Committee facilities requested that staff consider revised cost data. Staff gave a submittal deadline of March 12, 2021, for facilities to submit revised cost data and state that each cost data should be specific to the project to meet the targeted NOx limits. The submitted revised cost data will be reviewed by Norton Engineering, incorporated into the U.S. EPA SCR cost estimator, revise the BARCT assessment for the process heaters and boilers category. Furthermore, staff also stated in Working Group Meeting #19 held on March 4, 2021 that an evaluation of outlier units that are currently operating near 5 ppmv and low-use units will also be incorporated. The identified devices must accept an alternative limit in the permit and will be exempt from the 5 ppmv NOx limit. At Working Group Meeting #21 staff state the following conditions for devices when developing these conditional limits:

- Conditional limits are for units that currently have NOx control technology and achieving near the proposed limits
- In lieu of meeting the proposed BARCT limit, operators can accept permit limits at the conditional limit
- Devices must already meet the conditional limit and cannot retrofit new NOx controls to meet the conditional limit

As part of the cost-effectiveness reassessment based on the revised cost data, staff modified the BACRT analysis to integrate the incremental cost-effectiveness.

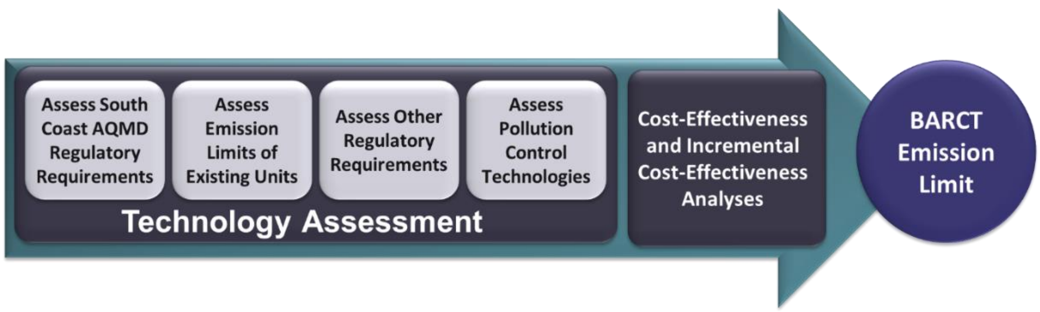


Figure B-10. BARCT Assessment Approach

As part of the March 2021 revised cost data submission, staff received 108 new or revised SCR estimates for the heaters and boilers; Data also included cost for SCR upgrades and ULNB/LNB projects for a few units. Staff received cost for 58 SCR projects in the first cost submission. Majority of the facility revised cost data was for heaters and boilers greater than or equal to 40 MMBtu/hr but also included cost for other category of equipment. SCR cost for the boiler and heater category ranged from $2 MM to $70 MM.

As part of the revised cost, staff requested the assistance of Norton Engineering for review of the cost data and provided the following comparisons:

- Revised burner costs were compared against a "typical" cost curve for burner upgrades
- Refinery's initial cost data compared to Norton Engineering's escalated cost estimates from the 2014 NOx RECLAIM BARCT feasibility study
- Refinery's revised cost data compared to Norton Engineering's escalated cost estimates from the 2014 NOx RECLAIM BARCT feasibility study (shown in graph below)
- Ratio of the refinery's initial and revised costs data

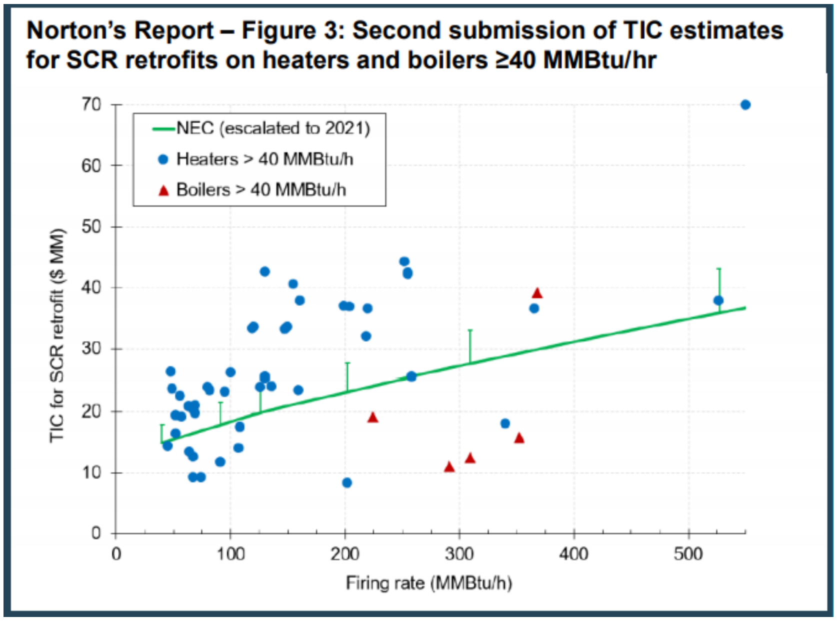


Figure B-11. Norton Engineering Report, second TIC submission

Norton Engineering's review and feedback regarding the facility revised cost data was presented in Working Group Meeting #22 on June 30, 2021. Norton Engineering's conclusion was that the costs provided by the facilities are not unreasonable, considering the potential complexity.

Facility-Revised Burner Costs

- Most of the facility-revised cost data for burners was consistent with "typical" costs
- 15 of the estimates were within expected range and 5 were outliers

Facility-Revised SCR Costs

- Norton's estimated SCR costs roughly passes through the middle of the refinery's initial cost data but is at the lower end of the facility-revised data
- 15 facility-revised datapoints were significantly higher
- Increases to the cost estimates are not unusual as project scope definition improves during the later stages of engineering design

Figure B-12 Facility Revised Burner and SCR costs

Based on Norton Engineering's recommendation, staff used all revised cost data submitted by facilities. Like the initial BARCT assessment, if cost for a specific device was provided, staff will use that cost in BARCT reassessment. In order to estimate costs for devices where costs were not provided, staff used all facility-revised data to update the power curve that will be used in U.S. EPA SCR cost model.

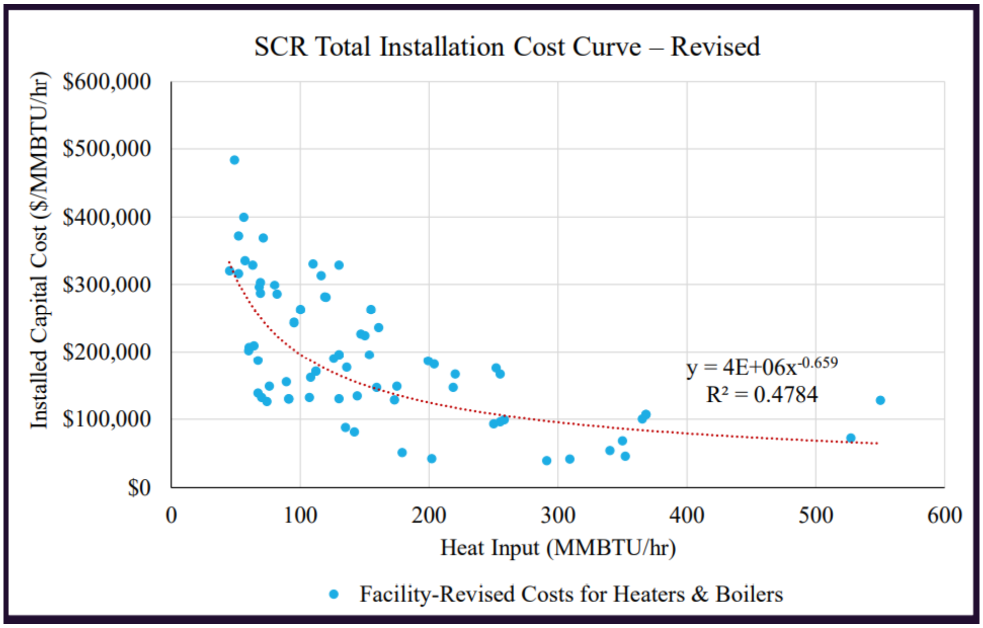


Figure B-13. Cost curve for SCR revised SCR TIC

Facilities also provided revised cost data for 20 LNB/ULNB projects. Staff used the revised cost data to update the cost curve used to estimate burner installations.

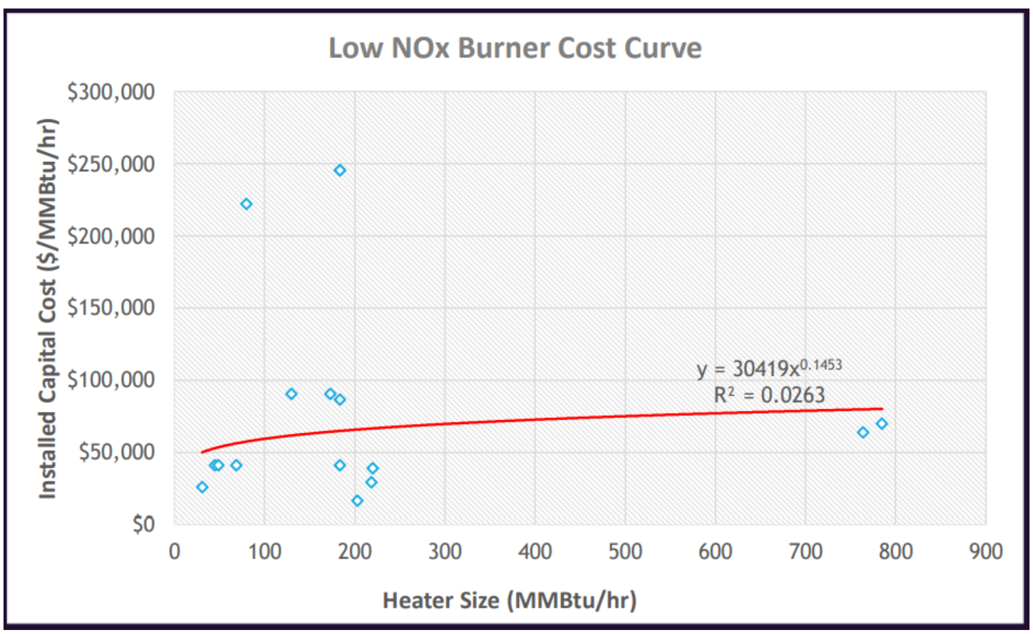


Figure B-14. Cost curve for revised LNB TIC

Once the cost estimate methodology has been updated, staff proceeded with the BARCT reassessment for the process heater and boiler category. Norton Engineering's final report concluded that sub-optimal burner conditions within a process heater will achieve 40 to 50 ppmv – this will be used to updates staff's prior conclusion that ULNBs can achieve 30 ppmv. The 30 ppmv is achievable under optimal conditions which are specified in API 535 recommended guidelines. In response to stakeholder feedback regarding the potential challenges and safety concerns of ULNB installation, the revised BARCT assessment will consider 50 ppmv as the achievable NOx level with burner control technology since this is the upper end of NOx range. The BARCT reassessment will be assessed as follows:

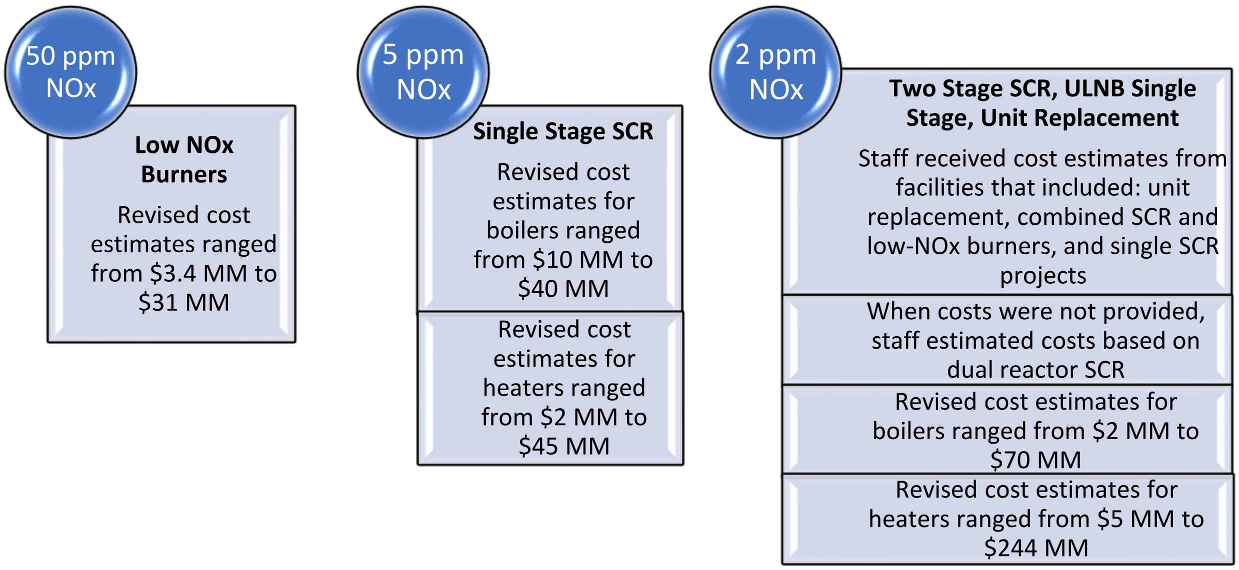


Figure B-15. BARCT reassessment for Process Heater and Boiler categories

Evaluating Conditional Limits

Based on the revised cost estimates provided by facilities, the average cost effectiveness to achieve ether 5 ppmv or 2 ppmv for heaters greater than or equal to 40 MMBtu/hr are above the $50,000 per ton of NOx. To reduce the average cost-effectiveness, staff proposed that devices operating between the proposed BARCT limit and conditional limits would not be required to meet the proposed NOx limit in Table 1 of the proposed rule; this applies to devices that are currently at or below the conditional limit. These conditional limits units are excluded from the cost-effectiveness calculation. An iterative process was used to identify the conditional limit NOx concentration level where the cost-effectiveness for devices above the conditional limit would be less than $50,000 per ton of NOx reduced. At 2 ppmv, no conditional limit was identified that will reduce the cost-effectiveness below $50,000 per ton of NOx reduced. At 5 ppmv, removing devices at or below the conditional limits will reduce the cost-effectiveness below $50,000 per ton of NOx reduced. Below is the iterative process used by staff to determine the conditional limits.

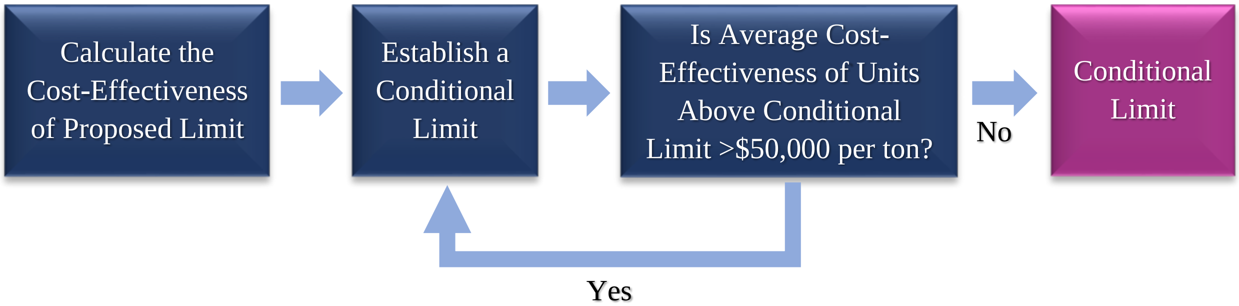


Figure B-16. Process of evaluating conditional limits

In the process of evaluating these conditional limits, staff identified several devices with combined stacks that consist of different sized heaters.

Staff also identified one unit greater than 110 MMBtu/hr that is operated at a low capacity of 12%. This unit has a high cost-effectiveness of $184,000 per ton of NOx reduced and low emission reductions at 0.02 tons per day. Staff will include a low-use provision exemption for devices operating less than 15% capacity – these low use devices will not be required to meet Table 1 limits in the rule.

In order to identify units that potentially qualify for the conditional limits, staff evaluated the NOx emissions reported in the 2018 survey. The NOx emissions reported in the survey are representative of the unit's annual average as reported by the facility. The conditional limits were presented at Working Group Meeting #22 on June 30, 2021. Stakeholders commented that staff should further evaluate the CEMS data based on a 24-hour rolling average for the conditional limit assessment; the evaluation will give a better representation of the unit's operation. Staff reassessed the CEMS based on the 24-hour rolling average recommendation while using the annual average in the survey as a screening step for further analysis of CEMS data. Below are staff's considerations when evaluating the CEMS data for a 24-hour rolling average:

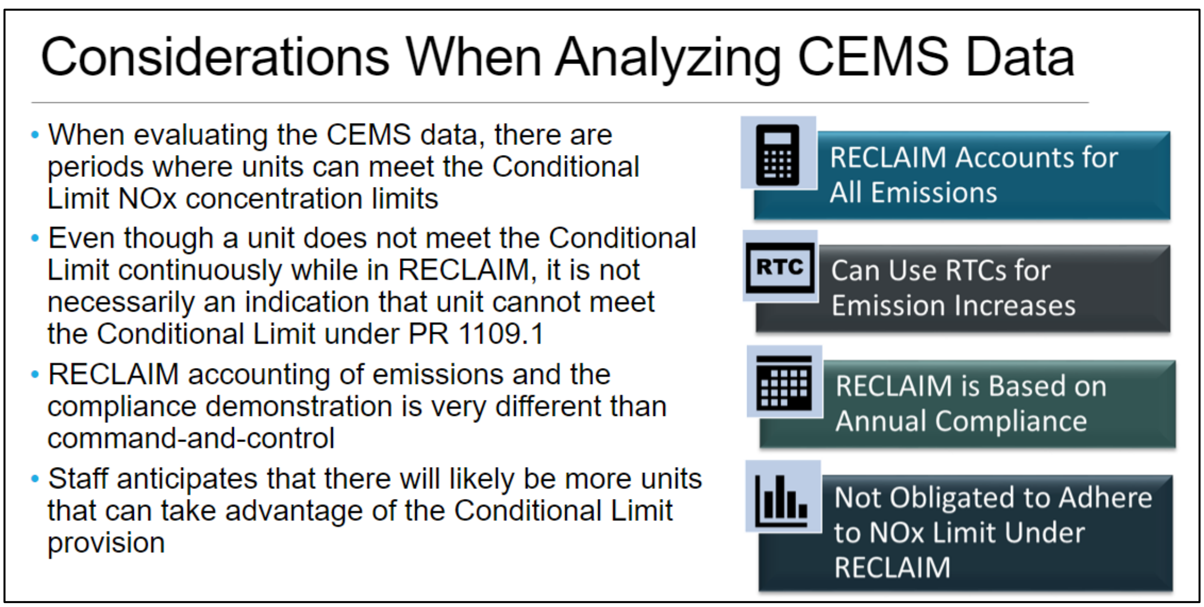


Figure B-17. CEMS data analysis considerations

Most of the units under RECLAIM do not have a permit limit, so there is no requirement to operate at a specific NOx level. However, during the CEMS analysis, any unit that had a permit limit typically operated below their permit limit 90% or more of the time. Staff believes this a good indication that under a command-and-control regulatory structure most of these units will be able to meet the BARCT limit or conditional limit. Staff identified units which are close to the conditional limit by using 80% as the threshold; if the conditional limit was 18 ppmv, then the CEMS for any unit performing at 14 ppmv of higher will be analyzed further. When analyzing the CEMS, staff conducted the conditional limit assessment in the following steps:

- **Step 1:** Identify units where the annual average NOx data is close to the conditional limit (80% of limit)
- **Step 2:** Identify and evaluate the percent of time a unit can achieve conditional limit over a 24-hour averaging period
- **Step 3:** If the unit cannot achieve the conditional limit for considerable amount of time, the unit will be removed
- **Step 4:** Re-assess the cost-effectiveness for category

Further CEMS analysis based on stakeholder feedback, identified three additional units as not close to the conditional limit. Staff removed each of the units form their respective categories and reassess the cost-effectiveness. Below is the result of the follow-up CEMS evaluation. The re-assessment table below was presented at a WSPA meeting held on August 6, 2021.

Table B-13. CEMS evaluation and reassessment for Process Heaters

Heater	Size (MMBtu/hr)	Annual Average NOx (ppm)	Proposed Conditional Limit (ppm)	Percent Below Conditional Limit (24-hr average)	Hours Below Conditional Limit (hours)
Heater 1	71.1	17.8	18	78%	6,708
Heater 2	52	14.7	18	86%	6,971
Heater 3	68	17.1	18	1%	6
Heater 4	82	17.6	18	38%	3,154
Heater 7	153	21.3	22	2%	127

The three heaters identified by staff were heaters 3, 4, and 7. Both heater 3 and 4 are in the 40 to 110 MMBtu/hr category and heater 7 is in the greater than 110 MMBtu/hr category. Staff re-assessed the initial conditional limit cost-effectiveness that was presented in Working Group Meeting #22.

Cost-Effectiveness and Conditional Limits

Process Heaters 40 to 110 MMBtu/hr

Staff used the iterative process at different concentration limits for the category and presented the analysis in Working Group Meeting #22 held on June 30, 2021. Staff initially identified 12 devices that are currently operating at NOx levels between 5 and 18 ppmv. Cost effectiveness for these units to meet 5 ppmv are high and range from $200,000 to $750,000 per ton of NOx reduced. The emission for these devices is low compared to other devices in category. Staff proposed a conditional limit of 18 ppmv for process heaters 40 to 110 MMBtu/hr and identified 12 heaters that qualified for the conditional limit. Excluding those units, the cost-effectiveness was less than $50,000 per ton as seen in the table below.

Table B-14. Potential Conditional Limits for process Heaters ≥ 40 - 110 MMBtu/hr

Process Heaters ≥ 40 - 110 MMBtu/hr			
Potential Conditional Limit (ppm)	Cost-Effectiveness of Remaining Units	Number of Units Meeting Conditional Limit	~~Forgone~~ Impact on Emission Reductions (tpd)
No Conditional Limit	$53,000	0/67 unit	None
10	$53,000	1/67 units	0.001
15	$51,000	8/67 units	0.02
18	$48,000	12/67 units	0.05

The re-evaluation identified two additional heaters that will potentially not meet the conditional limits in the 40 to 110 MMBtu/hr category. These two units were removed because they did not meet the 18 ppmv based on a 24-hour average and met the conditional limit less than 38% of time based on a 24-hour rolling average. The cost-effectiveness was reassessed in the table below.

Table B-15. Reassessment of Conditional Limits for process Heaters ≥ 40 - 110 MMBtu/hr

Process Heaters ≥ 40 - 110 MMBtu/hr			
Potential Conditional Limit (ppm)	Cost-Effectiveness of Remaining Units	Number of Units Meeting Conditional Limit	~~Forgone~~ Impact on Emission Reductions (tpd)
No Conditional Limit	$53,000	0/67 unit	None
18	$48,000	12/67 units	0.05
18	$50,500	10/67 units	0.02

After re-assessing the cost-effectiveness for the 40 to 110 MMBtu/hr category, the number of units staff identified as meeting conditional limit drops from 12 to 10 units and potential emission drops from 0.05 to 0.02 tons per day. The two units that were removed were placed back into the 40 to 110 MMBtu/hr category where the cost-effectiveness was recalculated and determined to be cost-effective at $50,500, so staff maintained the 18-ppmv conditional limit.

Once the cost-effectiveness and conditional limits were established, staff proceeded with the incremental effectiveness analysis where it was determined that going from 5 ppmv to 2 ppmv is above $50,000 per ton of NOx reduced.

Table B-16. Cost Effectiveness for Process Heaters ≥ 40 - 110 MMBtu/hr

Process Heaters 40 – 110 MMBtu/hr					
50 ppm		5 ppm		2 ppm	
Cost Effectiveness	Emission Reduction (tpd)	Cost Effectiveness	Emission Reduction (tpd)	Cost Effectiveness	Emission Reduction (tpd)
$40,000	0.33	$50,500	1.66	$94,000	1.99

Table B-17. Incremental Cost Effectiveness for Process Heaters ≥ 40 - 110 MMBtu/hr

	50 -> 5 ppm	5 -> 2 ppm
Incremental Cost Effectiveness	$50,000	$293,000
Incremental Emission Reduction (tpd)	1.33	0.33

Process Heaters Greater than 110 MMBtu/hr

Like the 40 to 110 MMBtu/hr process heater category, staff assessed the greater than 110 MMBtu/hr category for conditional limit units. Some heaters in the greater than 110 MMBtu/hr have very high NOx emission reduction potentials and in order to minimize the ~~amount of forgone~~ impact on the emission reductions, staff considered two additional criteria for evaluating the conditional limit:

1. Concentration limit
2. Overall emission reduction potential for NOx control retrofit

Staff conducted the assessment using the iterative process at different concentration limits but for devices with a potential to achieve greater than 20 tons per year reduction were not excluded from the category as conditional limits – these units will have to retrofit to meet Table 1 limits if they are still operating at the conditional limit. Staff initially identified 17 units (4 units are common stack) that are currently achieving NOx levels between 5 and 22 ppmv with less than 20 tons per day reduction potential. The average cost-effectiveness for conditional limit devices is approximately $85,000 per ton of NOx. Average cost-effectiveness for conditional limit devices with potential reduction greater than 20 tons per year is $44,000 per ton of NOx to meet the 5 ppmv BARCT, so units with potential reduction greater than 20 tons per year will not be excluded from the cost-effectiveness calculation to meet the 5 ppmv NOx limit. Staff will include a conditional limit of 22 ppmv for those units that have a potential NOx reduction less than 20 tons per year. Process heaters greater than 110 MMBtu/hr that meet this criterion are eligible to take advantage of the conditional limit and not required to retrofit to the 5 ppmv BARCT NOx limit.

Table B-18. Potential Conditional Limits for Process Heaters > 110 MMBtu/hr

Heaters > 110 MMBtu/hr			
Potential Conditional Limit (ppm)	Cost-Effectiveness of Remaining Units	Number of Units Meeting Conditional Limit	~~Forgone~~ Impact on Emission Reductions (tpd)
No Conditional Limit	$56,000	0/51 unit	None
10	$55,000	5/51 units	0.03
15	$54,000	8/51 units	0.06
18	$52,000	12/51 units	0.15
20	$50,500	13/51 units	0.19
22	$50,000	17/51 units	0.23

The table above was also presented at Working Group Meeting #22 and after further CEMS analysis based on stakeholder feedback, identified one heater (heater 7) that did not meet the conditional limit. Staff removed that unit and placed it back in to the greater than 110 MMBtu/hr heater category where the cost-effectiveness was reassessed for the category.

Table B-19. Reassessment of Conditional Limits for process Heaters > 110 MMBtu/hr

Process Heaters > 110 MMBtu/hr			
Potential Conditional Limit (ppm)	Cost-Effectiveness of Remaining Units	Number of Units Meeting Conditional Limit	~~Forgone~~ Impact on Emission Reductions (tpd)
No Conditional Limit	$56,000	0/51 unit	None
22	$50,000	13/51 units	0.23
22	$49,800	12/51 units	0.21

After removal of heater 7 from the conditional limit category, the number of units meeting the conditional drops from 13 to 12 – this updated number of units was initially 17 but revised to 13 to reflect units that share a common stack. The potential additional emission reduction also drops from 0.23 to 0.21 tons per day and the category remains cost-effectiveness at $50,000 per ton of NOx. After establishing the conditional limit for the greater than 110 MMBtu/hr category, staff proceeded with the incremental cost-effectiveness analysis where going from 5 ppmv to 2 ppmv was determined to be greater than $50,000 per ton of NOx.

Table B-20. Cost Effectiveness for Process Heaters Process Heaters > 110 MMBtu/hr

Process Heaters > 110 MMBtu/hr					
50 ppm		**5 ppm**		**2 ppm**	
Cost Effectiveness	**Emission Reduction (tpd)**	**Cost Effectiveness**	**Emission Reduction (tpd)**	**Cost Effectiveness**	**Emission Reduction (tpd)**
$72,000	**0.07**	**$49,800**	**1.86**	**$110,000**	**2.22**

Table B-21. Incremental Cost Effectiveness for Process Heaters > 110 MMBtu/hr

	50 to 5 ppm	5 to 2 ppm
Incremental Cost Effectiveness	**$49,000**	**$400,000**
Incremental Emission Reduction (tpd)	**1.79**	**0.36**

Boilers Greater than or Equal to 40 MMBtu/hr

Staff conducted a BARCT reassessment for the boilers greater than or equal to 40 MMBtu/hr category based on 5 ppmv and revised cost data from facilities. The revised cost data for the boilers greater than or equal to 40 MMBtu/hr category and staff methodology to estimate cost is presented below:

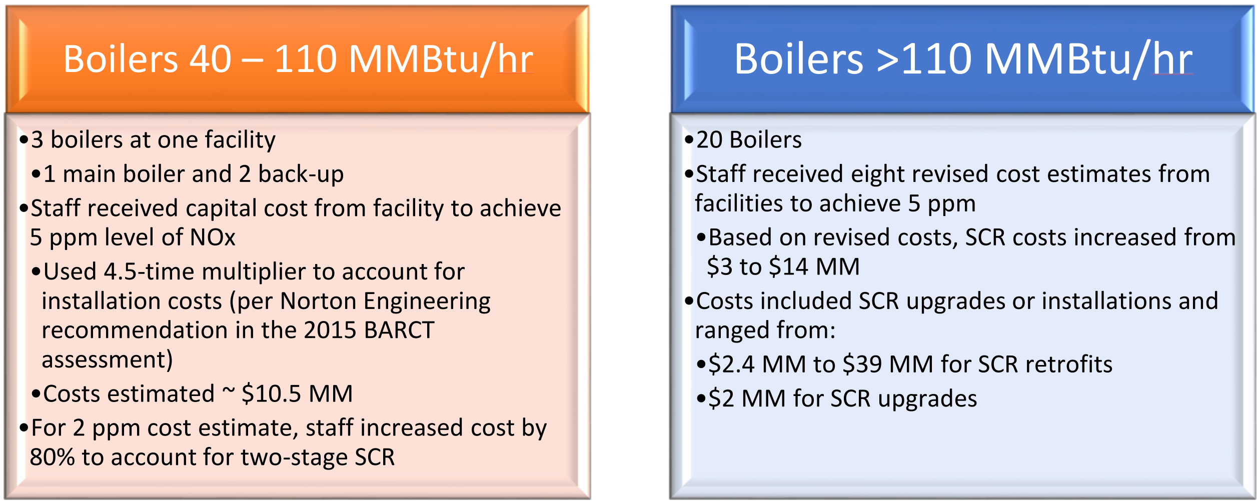


Figure B-12. Boilers BARCT Reassessment

The BARCT reassessment was presented at Working Meeting #22 on June 22, 2021 and concluded that 5 ppmv NOx limit is cost effective for both the 40 to 110 MMBtu/hr category and greater than 110 MMBtu/hr category at $37,000 and $12,000 per ton of NOx, respectively. In addition, staff also stated that no outliers were identified for the category. In addition, cost-effectiveness to achieving both 2 ppmv and 5 ppmv were well below $50,000 per ton of NOx removed. 5 ppmv NOx was recommended by staff due to technical feasibility concerns of installing a two stage SCR system due to available space.

Table B-22. Cost Effectiveness for Boilers ≥ 40 - 110 MMBtu/hr

Boilers ≥ 40 - 110 MMBtu/hr					
50 ppm		**5 ppm**		**2 ppm**	
Cost Effectiveness	**Emission Reduction (tpd)**	**Cost Effectiveness**	**Emission Reduction (tpd)**	**Cost Effectiveness**	**Emission Reduction (tpd)**
$13,000	**0.024**	**$25,000**	**0.049**	**$46,000**	**0.051**

Table B-23. Incremental Cost Effectiveness for Boilers ≥ 40 - 110 MMBtu/hr

	50 -> 5 ppm	5 -> 2 ppm
Incremental Cost Effectiveness	**$37,000**	**$656,000**
Incremental Emission Reduction (tpd)	**0.025**	**0.002**

The boilers 40 to 110 MMBtu/hr consist of three boilers located at one facility. These boilers currently do not have NOx controls, so no conditional limit is necessary for this category. Cost-effectiveness was calculated based on cost provided by the facility and is below $50,000 per ton of NOx. Staff's proposed BARCT limit for the category is 5 ppmv.

At Working Group Meeting #22, staff initially stated that no cost outliers were identified in greater than 110 MMBtu/hr category. However, upon review of the cost-effectiveness data and CEMS data, staff identified:

- Five boilers with a cost-effectiveness from approximately $75,000 to $8,000,0000
- Units performing at 7.5 ppmv or below based on CEMS annual average
- Based on CEMS analysis based on a 24-hour rolling average, all five boilers operate below 7.5 ppmv greater than 70% of the time (some were below >90% of the time)
- High cost-effectiveness due to low emission reductions (0.0001 to 0.007 tons per day)
- Providing a conditional limit of 7.5 ppmv will forgo 0.017 tons per day

Staff removed the five boilers operating below 7.5 ppmv based on a 24-hour rolling average and will include a conditional limit of 7.5 ppmv for the greater than 110 MMBtu/hr boiler category. The category remains cost-effective and drops from $12,000 to $11,000 per ton of NOx reduced.

Table B-24. Potential Conditional Limits for Boilers > 110 MMBtu/hr

Boilers > 110 MMBtu/hr			
Potential Conditional Limit (ppm)	Cost-Effectiveness of Remaining Units	Number of Units Meeting Conditional Limit	~~Forgone~~ Impact on Emission Reductions (tpd)
No Conditional Limit	$12,000	0/17 unit	None
7.5	$11,000	7/17 units	0.017

Staff reassessed the incremental cost-effectiveness after establishing the conditional limit of 7.5 ppmv for the greater than 110 MMBtu/hr category. Category remains cost-effective for 5 ppmv with the conditional limit units and incremental going from 5 ppmv to 2 ppmv is not cost-effective with the cost outliers removed.

Table B-25. Cost Effectiveness for Boilers > 110 MMBtu/hr

Boilers > 110 MMBtu/hr					
50 ppm		5 ppm		2 ppm	
Cost Effectiveness	Emission Reduction (tpd)	Cost Effectiveness	Emission Reduction (tpd)	Cost Effectiveness	Emission Reduction (tpd)
$12,000	0.72	$11,000	2.19	$18,000	2.30

Table B-26. Incremental Cost Effectiveness for Boilers > 110 MMBtu/hr

	50 -> 5 ppm	5 -> 2 ppm
Incremental Cost Effectiveness	$11,000	$159,000
Incremental Emission Reduction (tpd)	1.47	0.11

Steam Methane Reformer Heaters

The SMR heater sub-category consist of eleven heaters and one SMR with an integrated gas turbine. Staff initially only included six SMR heaters that are fired primarily with PSA-off gas which has a higher hydrogen content. The hydrogen present can contribute to higher adiabatic flame temperatures which results in a higher NOx potential. The other five SMR heaters are fired exclusively on refinery fuel gas and originally included in the process heater category, but stakeholder commented that all SMR heaters should be in the SMR heater category regardless of fuel type. SMR heaters fired on refinery fuel gas are configured and operated similar to their PSA-gas fueled counterparts. All SMR heaters have:

- Large number of burners that are necessary to maintain even heat flux across the heater
- Similar design and arrangement
- Higher operating temperature than traditional process heaters – higher temperature needed to drive hydrogen reaction in process tubes

All SMR heaters are greater than 110 MMBtu/hr in size and are currently equipped with some form of NOx control except for two heaters that will require SCR. Five heaters in this category are performing at or below 5 ppmv NOx. Staff excluded any heater currently performing at or below 5 ppmv from the cost-effectiveness calculation. At Working Group Meeting #11 held on May 21, 2020, staff presented the initial BARCT assessment for six SMR heaters fueled by PSA-off gas. Staff evaluated both 5 ppmv and 2 ppmv. The initial cost-effectiveness only considered one unit that was performing above 5 ppmv; the other units are currently have controls and performing less than 5 ppmv and concluded that it was cost-effective for the unit to go to 5 ppmv with an SCR upgrade. Staff also determined that it was not incrementally cost-effective to go to 2 ppmv since it would require LNB replacement and a SCR upgrade.

Table B-27. Cost Effectiveness for SMR Heaters

Cost Effectiveness		
Heater Category	32 ppm (LNB & SCR Upgrade)	5 ppm 5 ppm (SCR Upgrade)
SMR and Gas Turbine **SMR Heaters**	$69,054 $138,781	Currently Performing $45,909

At Working Group Meeting #13 held on August 12, 2021, staff provided a follow up BARCT assessment to the SMR heater category that included all eleven units regardless of fuel type. Staff also conducted a new cost-effectiveness evaluation of the SMR heater category based on a 5 ppmv BARCT limit. In addition, staff also evaluated the CEMS using a 24-hour rolling average and concluded that most units are able to meet the 5 ppmv a majority of the time.

Table B-28. SMR Heaters Current NOx Control and Required Control to meet 5 ppmv

SMR Heater	Current NOx Control	NOx Control Required to meet 5 ppmv	Primary Fuel
1	LNB/SCR	SCR Upgrade	PSA
2	LNB/SCR	SCR Upgrade	PSA
3	LNB/SCR	No Action	PSA
4	LNB/SCR	No Action	PSA
5	LNB/SCR	No Action	PSA
6	LNB/SCR	SCR Upgrade	PSA
7	SCR	SCR Upgrade	RFG
8	SCR	SCR Upgrade	RFG
9	No SCR	New SCR Install	RFG
10	No SCR	New SCR Install	RFG
11	LNB/SCR	No Action	RFG

Three of the six SMR heaters fired on PSA-off gas currently meet 5 ppmv and require no action, so they were excluded from the cost-effectiveness. The other three units were included in the cost-effectiveness and required SCR upgrades. For SMR heaters fired on refinery gas, one heater currently meets the 5 ppmv and requires no action and excluded from the cost effectiveness. Two heaters will require SCR upgrades and two heaters will require brand new SCR installations – these four units were included in the cost-effectiveness.

Table B-29. Cost Effectiveness for all SMR Heaters to 5 ppmv

Cost Effectiveness for all SMR heaters (PSA off-gas and RFG)	
Heater Category	5 ppm
SMR Heaters	$15,041

Based on the BARCT reassessment for the SMR heater category, staff determined that it was cost-effective for the category to go to 5 ppmv. Staff proposed a BARCT of 5 ppmv at 3% O_2 based on a 24- hour rolling average. Stakeholders requested that staff re-evaluate the cost-effectiveness to retrofit units achieving near the proposed 5 ppmv BARCT limits based on the revised cost data submitted by facilities in March 2021. Staff presented and discussed the follow-up assessment at Working Group Meeting #21 held on May 27, 2021. Staff evaluated the annual average and CEMS data and identified several units that were performing near 5 ppmv. Staff estimated that SCR upgrade costs to be in the range of $4 MM to $7.1 MM, but based on the recommendation of Norton Engineering, staff increased the upgrade costs to $7.5 MM to $10 MM. Staff identified three outlier units that had high cost-effectiveness and low emission reduction of 0.015 tons per day.

Table B-30. Cost Effectiveness for SMR Heaters with low emission reductions

Cost Effectiveness
7.2 ppm -> 5 ppm NOx Limit
$242,000

Staff concluded that it was not cost-effective for these outlier units to retrofit to 5 ppmv, so staff proposed a near conditional limit of 7.5 ppmv for the SMR heaters. Staff removed these outliers from the SMR heater category evaluation and re-evaluated the costs for the remaining units.

Table B-31. Cost Effectiveness for SMR Heaters after taking outliers

Cost Effectiveness
5 ppm NOx Limit
$17,000

Based on the reassessment, it is still cost-effective at $17,000 for the remaining units to achieve 5 ppmv. Staff maintained a BARCT limit of 5 ppmv for the SMR heater category and will include a conditional limit of 7.5 ppmv.

Steam Methane Reformer Heater with Integrated Gas Turbine

The SMR heater with an integrated gas turbine is a unique arrangement comprised of a gas turbine and an SMR heater that share a combined stack. Staff also consulted with Norton Engineering for recommendations on how to properly address this system. Norton Engineering recommended that due to the unique arrangement and configuration, it should be evaluated as a system in its own subcategory. The gas turbine is located upstream of the heater and under normal integrated operation, a portion of the gas turbine exhaust provides combustion air for the burners in the SMR heater, and the remaining turbine exhaust exits the combined stack. The unit currently has LNB and SCR for NOx controls and has a permit limit of 9 ppmv at 15%O_2. The BARCT assessment for the category was presented and discussed at Working Group Meeting #11 on May 21, 2020. The current emissions for the unit are less than 5 ppmv at 15% O_2 on an annual basis and in order to maintain a 5 ppmv staff concluded that the existing SCR can be upgraded to improve or maintain the NOx reduction efficiency. Since this system is also impacted by the operation of the gas turbine, staff evaluated the BARCT at 3 ppmv and 5 ppmv. Staff assumed the cost for an SCR upgrade to be 30 percent of a new SCR and O&M increase of 20% associated with the upgrade.

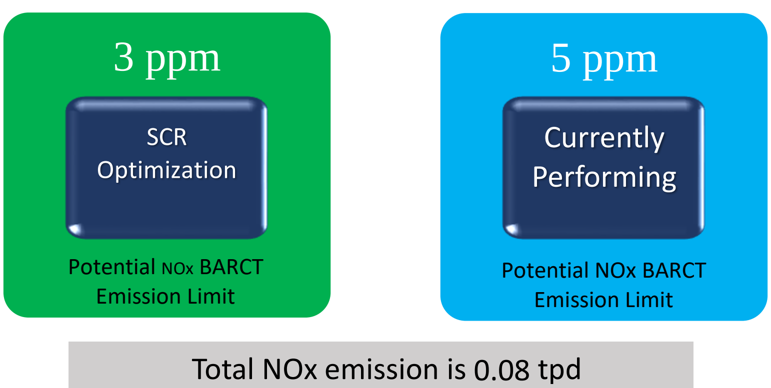


Figure B-13. Summary of BARCT Assessment

No other NOx limit was cost-effectiveness therefore staff did not calculate the incremental cost-effectiveness for this equipment category, so staff proposed a BARCT limit of 5 ppmv at 15% O_2 for SMR heater with gas turbine.

Table B-32. Cost Effectiveness for SMR Heaters with Gas Turbine

Cost Effectiveness		
Heater Category	3 ppm (SCR Upgrade)	5 ppm
SMR Heater with Gas Turbine	$69,054	Currently Performing

Startup Heaters

There are five heaters in this category and all heaters are associated with the FCCU. The startup air heaters are located within the FCC operating units and only used during startup of the FCC regenerator. The NOx emissions from these heaters exit the same stack as the FCC regenerator and since most of the FCCs already have a SCR, adding a second SCR is not feasible since the SCR will more than likely not reach optimal operating temperature for an extended period of time. Once the FCCU regenerator is up to operating temperature, these heaters are shut off and no longer used. Annual emissions from this category are 0.0029 tons per day based on 2017 annual emissions data. Staff estimated SCR cost for these startup air heaters using the revised U.S. EPA cost model and determined this category is not cost-effective at $1.7 MM per ton of NOx reduced. Staff proposes a low-use exemption of 200 hours per year for this category. No incremental cost-effectiveness was calculated as no additional NOx control technology was identified.

Sulfuric Acid Furnaces

There are two sulfuric acid plant furnaces in this category – one is an operating unit within a refinery and the other is a standalone plant. Both facilities regenerates spent sulfuric acid used in the refinery alkylation process where the main feedstock is spent sulfuric acid. Depending on the ratio of feedstock used at each facility, fuel gas demand will vary. The process and operation for both is similar and therefore NOx controls are similar. Staff presented the BARCT assessment for this category at Working Group Meeting #13 held on August 12, 2020 and a follow-up BARCT assessment at Working Group Meeting #15 on November 4, 2020. At WGM #13 staff evaluated the feasibility of several potential NOx control options which included LNB, SCR, and LoTOx™.

After meeting with the manufacturer and receiving estimates, staff conducted the cost effectiveness based on a potential BARCT limit of 20 ppmv and 2 ppmv.

<u>Low-NOx Burners (LNB)</u>

Each of the furnaces is equipped with two burners, but only one is equipped with LNB. LNBs for this application are specialized for high sulfur and high temperature applications. Both units operate at very high temperatures at 2,200 ºF, so LNB must be robust and engineered for the specific application. Based on vendor feedback, NOx reductions from LNBs are between 25% to 50% from traditional burners. Based on vendor feedback custom designed LNB will typically achieve between 25 to 30 ppmv. One facility provided staff with a cost estimate for LNBs installation at their facility which was approximately $4.5 MM and using the revised LNB cost-curve at approximately $3.2 MM. Based on the cost estimates, it was determined that LNBs at 20 ppm was cost-effective at $50,000 per ton of NOx.

Selective Catalytic Reduction (SCR)

For SCR, staff identified two potential locations in the production process where it can be installed, Upstream of the catalytic converter and downstream of the scrubber. For each location staff also identified several potential issues with SCR that may impact the feasibility and costs.

Upstream of catalytic converter	Downstream of scrubber
• Ammonia may adversley impact process and foul catalyst in converter • Major re-engineering and process modification required • Increases cost • Not preferred	• Low temperature • Flue gas reheating to 600 F, supplemental firing may be required • Potential impacts on SOx emission control needs to be considered

Figure B-14. Potential locations for installing SCR

SCR cost-effectiveness was based on SCR cost estimate using the revised U.S. EPA cost spreadsheet with the assumption of a downstream installation which will require flue gas reheating. Staff's calculated that a duct burner with a rated heat input of approximately 43 MMBtu/hour will be necessary to raise the flue gas temperature to 600 ºF. The additional cost was estimated as follows:

- $4 MM cost increase for the duct burner and larger SCR due to accommodate additional NOx reduction from burner
- Additional NOx increases of 0.25 tons per year
- Additional Natural gas cost to fuel duct burner at $1.79/MMBtu

Once all additional costs were incorporated, it was determined that it was not cost-effective for SCR at $68,000 per ton of NOx reduced.

Low Temperature Oxidation (LoTOx™) with Wet Gas Scrubber

Both sulfuric acid plants currently have a wet scrubber downstream of the process for SOx control. LoTOx™ is a potential technology that can be used since scrubber technology is currently being employed. The technology uses ozone injection in conjunction with a wet scrubber system to remove NOx in the flue gas. Ozone generation equipment is required on site and can be modulated on demand depending on the removal efficiency required. The annual operating cost for a LoTOx™ system is higher when compared to SCR and the facility may be required to upgrade their waste effluent treatment system to treat the wastewater generated. The advantage of the LoTOx™ system is that it is a multipollutant control system that can be used to control SOx in addition to NOx. One advantage of LoTOx™ over SCR is that LoTOx™ does not require a high operating temperature, optimal temperature range is 200ºF to 300ºF. Potential location for the system is after the absorber tower(s). LoTOx™ cost estimate based on vendor quote of $15 MM with annual operating cost of approximately $1 MM. It was determined that LoTOx™ was not cost-effective.

Table B-33. Cost Effectiveness for Sulfuric Acid Plant Furnaces

Cost Effectiveness			
Equipment	**2 ppm**		**20 ppm**
Sulfuric Acid Plant Furnaces	**SCR**	**LoTOx**	**LNB**
	$68,000	$92,000	$50,000

Based on the BARCT assessment staff concluded that the only cost-effective option is custom designed LNB. Staff initially proposed a 20 ppmv for the sulfuric acid furnace but was later revised to 30 ppmv based on the recommendation of Norton Engineering. Since both furnaces are operating at or below the 30 ppmv, staff does not anticipate any cost for the category.

Startup Heaters and boilers at Sulfuric Acid Plants

Each of the two Sulfuric acid plants have startup heaters which are used to heat up the catalytic converter during periods of unit startup. Once the catalytic converter is up to temperature, the heater is shut off. Only one facility has a startup boiler that is operated when the facility is down for maintenance – plant steam is generated through heat recovery from the furnace flue gas. The boiler is equipped with a LNB. All startup heaters and boilers are permitted for use during startup of the acid plant only and is limited on annual firing rates – 23,000 to 90,000 MMBtu per year. Total NOx emissions for this category is 0.0011 tons per day. Staff evaluated the cost-effectiveness of achieving 2 ppmv with SCR/LNB combination and 20 ppmv with new LNB.

Table B-34. Cost Effectiveness for Start-Ip Heaters and Boilers at Sulfuric Acid Plants

Cost Effectiveness		
Heater Category	2 ppm (LNB+SCR)	20 ppm (LNB)
Start-Up Heaters	$2.2 MM	$334,630
Start-Up Boilers	$3.3 MM	$4.8 MM

Either control options were determined to be not cost-effective, so staff proposed to allow a use exemption for the startup heaters and boilers and maintain current permit limit on firing rate per year. No incremental cost-effectiveness was calculated as there were no additional NOx control technologies identified.

Proposed BARCT Limits for the Heaters and Boilers Category

Process Heaters

Table B-35. Proposed BARCT Limits for Process Heaters

Refinery Equipment Category	No. of Units	Emission Limits (ppmv)		Averaging Time	2017 NOx Emissions (tpd)	NOx Emission Reduction (tpd)	Cost-Effectiveness
		NOx	Cond. Limit				
Process Heaters (size in MMBtu/hour)							
<40	67	40/9	--	2 hours	0.49	0.031	$16,000/-[1]
≥40 - ≤110	67	5	18	24 hours	2.05	1.65	$50,500
>110	51	5	22	24 hours	2.52	1.58	$49,800

[1] Some additional costs incurred upon burner replacement.

Boilers

Table B-36. Proposed BARCT Limits for Boilers

Refinery Equipment Category[(1)]	No. of Units	Emission Limits (ppmv)		Averaging Time	2017 NOx Emissions (tpd)	NOx Emission Reduction (tpd)	Cost-Effectiveness
		NOx	Cond. Limit				
Boilers (size in MMBtu/hour)							
<40	5	40/5	--	2 hours	0.02	--	$-[1]
≥40 - ≤110	3	5	--	24 hours	0.052		$25,000
>110	20	5	7.5	24 hours	2.55	2.19	$11,000

[1] Some additional costs incurred upon burner replacement.

Steam Methane Reformer Heaters

Table B-37. Proposed BARCT Limits for Steam Methane Reformer Heaters

Refinery Equipment Category	No. of Units	Emission Limits (ppmv)		Averaging Time	2017 NOx Emissions (tpd)	NOx Emission Reduction (tpd)	Cost-Effectiveness
		NOx	Cond. Limit				
SMR Heaters							
All	11	5	7.5	24 hours	1.02	0.62	$17,000

Steam Methane Reformer Heater with Gas Turbine

Table B-38. Proposed BARCT Limits for Steam Methane Reformer Heater with Gas Turbine

Refinery Equipment Category	No. of Units	Emission Limits (ppmv)		Averaging Time	2017 NOx Emissions (tpd)	NOx Emission Reduction (tpd)	Cost-Effectiveness
		NOx	Cond. Limit				
SMR Heater & Gas Turbine							
All	2	5	--	24 hours	0.082	--	$0

Startup Heaters

Table B-39. Proposed BARCT Limits for Startup Heaters

Refinery Equipment Category	No. of Units	Emission Limits (ppmv)		Averaging Time	2017 NOx Emissions (tpd)	NOx Emission Reduction (tpd)	Cost-Effectiveness
		NOx	Cond. Limit				
Startup Heaters (MMBtu/hour)							
≥40 - ≤110	2	Low-Use	--	--	0.002	--	$0
>110	3	Low-Use	--	--	0.0007	--	$0

Sulfuric Acid Furnace

Table B-40. Proposed BARCT Limits for Sulfuric Acid Furnace

Refinery Equipment Category	No. of Units	Emission Limits (ppmv)		Averaging Time	2017 NOx Emissions (tpd)	NOx Emission Reduction (tpd)	Cost-Effectiveness
		NOx	Cond. Limit				
Sulfuric Acid Furnace							
Furnace	2	30	--	365 day	0.097	--	$0

Start-up Heaters and Boilers located at Sulfuric Acid Plants

Table B-41. Proposed BARCT Limits for Start-up Heaters and Boilers at Sulfuric Acid Plants

Refinery Equipment Category	No. of Units	Emission Limits (ppmv)		Averaging Time	2017 NOx Emissions (tpd)	NOx Emission Reduction (tpd)	Cost-Effectiveness
		NOx	Cond. Limit				
Process Heaters (size in MMBtu/hour)							
<20	1	Low-Use	--	--	0.0002	--	$0
≥40 - ≤110	2	Low-Use	--	--	0.0009	--	$0

APPENDIX C PETROLEUM COKE CALCINER

Petroleum Coke Calciner

The Marathon (Tesoro Refinery) petroleum coke calciner is the only facility of its kind in the South Coast Air Basin and is currently operating within the NOx RECLAIM program. The BARCT assessment was initiated and presented in Working Group Meeting #2 on June 14, 2018 and completed and presented during Working Group Meeting #12 held on July 17, 2020.

Process Description

Coke calcining is a process that improves the quality and value of green petroleum coke, which is produced at petroleum refineries in the delayed coker unit. The Tesoro Calciner processes green petroleum coke produced by the nearby Tesoro Carson Refinery. The dried green petroleum coke is introduced into the high end of the rotary kiln, tumbled by rotation, and moved down the kiln countercurrent to a hot stream of combustion air to drive off the moisture, impurities, and hydrocarbons. After discharging from the kiln, the calcined petroleum coke drops into a cooling chamber, where it is quenched with water, treated with dedusting agents for dust control, and carried by conveyors to storage silos. The calcined coke product is sold to various industries such as the aluminum, steel, specialty chemical, and cement industry and is also sold and used as fuel.

A simplified process diagram of the coke calcining process is shown in the figure below1. Green petroleum coke is fed to the 120 MMBtu per hour rotary kiln which has a combination burner capable of firing natural gas and diesel fuel to combust volatile hydrocarbons and an oxygen injection system for additional control of VOC and CO emissions. The residence time in the rotary kiln is approximately one hour. Exhaust gases from the kiln enters the 130 MMBtu per hour pyroscrubber afterburner where entrained particulates, residual VOCs, and other combustible gases, including CO, are oxidized. Once treated in the primary dust collector (C66), dust-laden air from the coke cooler is also fed to pyroscrubber afterburner for combusting volatile hydrocarbons. The temperature in the pyroscrubber is maintained at 2,200°F or greater as required by permit condition. The hot gases from the pyroscrubber then pass through the waste heat recovery boiler (D104) to generate steam which is used for electrical power generation. The gases leave the waste heat recovery boiler at 450°F and continue to the lime scrubber spray chamber reactor (C68) where lime slurry is introduced to the gas stream via an atomizer which generates liquid droplets. The lime slurry droplets react with the SOx in the flue gas to form calcium sulfates and calcium sulfites to reduce SOx emissions. The gases leave the spray dryer at approximately 210°F and is routed to the main baghouse (C69) which consists of 12 modules. Each module contains 1,689 Teflon-coated fiberglass bags, 8 inches in diameter and 26 feet in length to control PM emissions. A bag leak detection system monitors relative changes of PM emissions in each module and differential pressure across the baghouse. The gas is drawn through the baghouse by an induced draft fan and is discharged to the atmosphere through the main stack (S71). NOx controls could be installed at several places in the process (highlighted with numbers 1 – 4 on Figure 1). These locations are compared in this analysis with respect to the effectiveness of different NOx control technologies.

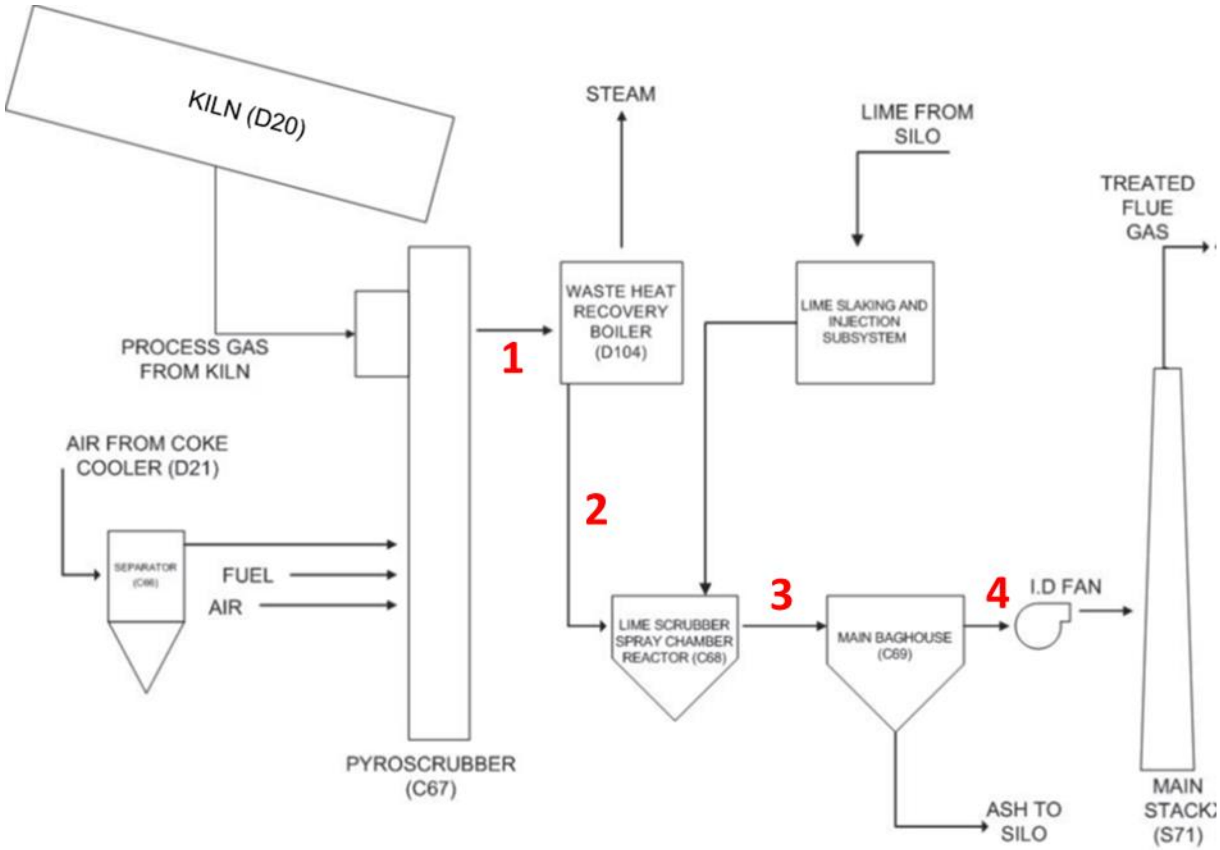


Figure C-1. Coke Calciner Process and Potential Locations for NOx Control (Numbered in Red)

BARCT Assessment

Assessment of South Coast AQMD Regulatory Requirements

There are no specific South Coast AQMD regulatory requirements for petroleum calciner beyond the requirements in RECLAIM. BARCT assessments were conducted in 2005 and 2015 as part of the RECLAIM program which established a NOx permit limit equivalency of 30 ppmv and 10 ppmv, respectively (see table below). For *non-refinery* kiln/calciners, such as cement kilns, Rule 1147 – *NOx Reductions from Miscellaneous Sources* established a 60 ppmv NOx limit. The process and operation of cement kilns is similar to that of the petroleum coke calciner, but the feedstock is different.

Table C-1. South Coast AQMD Rules NOx Limits

Refinery Rule Limits and Assessments		
	2005 RECLAIM BARCT	2015 RECLAIM BARCT
Petroleum Refining, Calciner	30 ppmv	10 ppmv
Non-Refinery Rule Limits		
Rule 1147 – NOx Reductions from Miscellaneous Sources		
Calciner and Kiln (≥1200°F)	60 ppmv at 3% O_2, dry or 0.073 lb/MMBtu	

Assessment of Emission Limits of Existing Units

The Marathon (Tesoro Refinery) calciner is regulated under RECLAIM, which is a mass emission-based program, so no NOx concentration permit limits were established for the kiln and pyroscrubber. Staff did not identify any petroleum coke calciners currently equipped with NOx control equipment at petroleum crude refineries but did identify similar rotary kiln processes used in the cement and lime industry. BP Cherry Point refinery in Blaine, Washington has a coke calcining operation that uses three calciner hearths rather than a kiln process. The hearths are equipped with caustic scrubbers and a wet electrostatic precipitator for PM and sulfuric acid control, but no NOx controls. The coke calciner the single largest source of NOx emissions in the PR 1109.1 universe.

Staff assessed the emissions limits of existing units, in the case of the petroleum coke calciner, there is only one unit to assess. Based on NOx survey questionnaire, Marathon (Tesoro Refinery) operates one coke calciner that has two connected combustion devices, a rotary kiln and pyroscrubber that share a common stack equipped with a single CEMS. There are no existing NOx controls, but the equipment has controls for SOx and PM. The 2017 NOx emissions from the coke calciner and current NOx outlet concentration are listed in the following table.

Table C-2. 2017 NOx Emissions for Coke Calciner

Equipment	2017 NOx Emissions (lbs)	Outlet NOx (ppmv) @ 3% O_2
Rotary Kiln	521,986	65 to 85
Pyroscrubber		
Total (tpd)	**0.71**	

Assessment of Other Districts NOx Rules and Limits

Staff assessed other rules and regulations outside the South Coast jurisdiction that regulate sources similar to a petroleum coke calciner, which is summarized in the following table.

Table C-3. Non-South Coast AQMD Rules NOx Limits

San Joaquin Valley Air Pollution Control District		
Rule 4313 – Lime Kilns		
Fuel Type	**NOx Limit (ppmv*) at 3% O_2, dry**	**NOx Limit (lb/MMBtu)**
Gaseous Fuel	82.6	0.10
Distillate Fuel Oil	93.72	0.12
Residual Fuel Oil	165.2	0.20
*** Converted ppmv emissions**		

Texas Commission on Environmental Quality	
Title 30, Part 1, Chapter 117, Subchapter B, Division 3, Rule §117.310 – Emission Specifications for Attainment Demonstration	
Kiln Type	**NOx Limit**
Lime Kilns	0.66 lb per ton of calcium oxide
Lightweight Aggregate Kilns	1.25 lb per ton of product

Assessment of Pollution Control Technologies

There are several unique challenges to the coke calciner, including the impacts from controlling other pollutants, such as Sox and PM, and the high operating temperature required to achieve VOC destruction. Due to the high operating temperature requirements, combustion modifications, such as LNBs, will not provide significant NOx reductions. Staff explored three feasible NOx control technologies: SCR, LoTOx™, and UltraCat™, which are all capable of achieving greater than 95 percent. LoTOx™ and UltraCat™ are both multi-pollutant control technologies so they may be able to replace existing SOx and PM controls.

The two categories of NOx controls are combustion modifications and flue gas treatment techniques. Staff evaluated both combustion modification and flue gas treatment techniques for the coke calciner and determined flue gas treatment techniques are the most effective form of NOx control in terms of emission reductions. Combustion modification controls, such as the current low NOx burner technology, may not be feasible due to operational constraints, and would not result in significant NOx reductions. There are two burner systems used in the coke calcining process. The first is used to heat the green coke in rotary kiln and is rated at 120 MMBtu per hour and can fire on either natural gas or diesel fuel. This burner is designed to operate close to stoichiometric combustion to minimize the oxygen content of the products of combustion to prevent possible undesirable ignition of the coke material. Traditional low NOx burners utilize additional excess air or staged combustion, which would not work for the coke calciner due to the introduction of excess oxygen into the kiln. The second burner system is used in the pyroscrubber. It is rated at 130 MMBtu per hour and can also fire on natural gas or diesel fuel. The function of this burner is to preheat the pyroscrubber prior to start of the kiln. Once the kiln is in full operation, the heat release from the incineration of VOCs and coke dust entering the pyroscrubber provides enough energy to allow the startup burners to be turned down or shut off completely. The burners can potentially be upgraded to a low NOx design, but they only run for a short period of time at startup and only contribute a small percentage of the overall NOx emissions. Performing an emissions balance of the coke calciner shows that fuel combustion from the burners contributes approximately 8 tons (4 percent) to the total yearly NOx emissions. The primary source of NOx emissions in the pyroscrubber is from combustion of the VOCs and coke particulates; thus, the most effective NOx control is flue gas treatment. Ideally, the NOx control device should be located either downstream of waste heat boiler or baghouse due to the high flue gas temperatures coming off the pyroscrubber. Locations for potential flue gas treatment NOx control are shown in Figure C-1 and listed in the table below.

Table C-4. Potential Locations for Flue Gas NOx Treatment

Location Number	Description
Location 1	Pyroscrubber to Waste Heat Boiler
Location 2	Waste Heat Boiler to Lime Scrubber
Location 3	Lime Scrubber to Baghouse
Location 4	Baghouse to Main Stack

Based on staff's assessment of control technologies, commercially available flue gas treatment NOx control technologies for the coke calciner are LoTOx™, SCR, and UltraCat™. LoTOx™ and UltraCat™ are commercially available multi-pollutant control technologies that can operate at low temperatures in the removal of NOx, SOx, and PM.

LoTOx™ with Wet Gas Scrubber

For the LoTOx™ application at the coke calciner, staff identified location 2 as the ideal location for the technology, but the temperature of 450°F out of the waste heat boiler will be an issue. As mentioned in the discussion on LoTOx™ control technology, the process requires ozone in order to convert the NOx into water soluble N_2O_5. The LoTOx™ technology has an upper temperature limit of 300°F for the flue gas temperature into the scrubber due to the half-life decay of ozone back to oxygen. In order to overcome this issue, a considerable amount of oxygen will be required at temperatures greater than 300°F. BELCO will typically recommend a water quench step to reduce the temperature below the 300°F, thus location 2 at the coke calciner will require a quench system in addition to the LoTOx™ system.

Selective Catalytic Reduction

If a SCR is used to reduce NOx emissions in the coke calciner, the location for the SCR needs to be considered. Staff identified four potential locations which consider temperature, coke dust/particulate loading, catalyst type, and whether flue gas reheating will be required. Most SCR catalyst manufacturers typically avoid "dirty" or high particulate/dust systems to reduce the risk for catalyst plugging. In addition, petroleum coke dust contains metals such as sodium, nickel, and vanadium; vanadium which will deactivate the catalyst and lower its activity. Flue gas temperature is also a critical factor in achieve optimum NOx removal and temperatures in the calciner ranges from 2,200°F to 200°F, so flue gas reheating may be required depending on location. However, the new generation of low temperature catalyst does increase the potential locations for the SCR without the need for much flue gas reheating. A vertical down flow SCR system is also recommended to help reduce overall footprint and layout. Based on these considerations, staff concluded that Location 4 is the most suitable location for an SCR application based on the criteria in the following table.

Table C-5. Assessment of Ideal Location for an SCR Application

	Location 1	Location 2	Location 3	Location 4
	Pyroscrubber to waste heat boiler	Waste heat boiler to lime scrubber	Lime scrubber to baghouse	Baghouse to main stack
Appropriate Temperature	No	Yes	No	No
Particulate/dust Plugging of Catalyst	Yes	Yes	Yes	No
Potential for Metal Deactivation	Yes	Yes	No	No
Flue Gas Reheating Required	No	No	Yes	Yes
Potential Location of NOx Control	No	No	No	Yes

Location 1: The temperature at this location can be as high as 2,200°F which is beyond the effective temperature range for most SCR catalyst operation. The location also has the potential for coke particulate plugging. Location 1 is not ideal for SCR installation and not recommended.

Location 2: The temperature is approximately 450°F and is ideal for a low temperature catalyst but has the potential for catalyst plugging due to coke particulates/dust from the process. An assessment of the particle size distribution and solids loading should be performed to further evaluate feasibility. The SO_3 levels at this location is also not known and may present an issue with ammonium bisulfate formation which may deactivate the catalyst. Location 2 is also not ideal for SCR installation and not recommended.

***Location 3*:** The temperature at this location is approximately 200°F and will require flue gas reheating. This location also has the potential for catalyst plugging due to the dry lime sorbent injection located just upstream. Most SCR vendors typically will recommend avoiding “dirty” or high particulate systems if possible, so this location is also not an ideal location and not recommended.

Location 4: Similar to Location 3, the temperature is approximately 200°F and is too low to get meaningful NOx reductions, even with a low temperature catalyst. The flue gas temperature would need to be increased to at least 400°F at the face of the catalyst for proper catalyst operation, preferably at 450°F to reduce the potential for ammonium bisulfate formation. Flue gas reheating can be accomplished with a duct burner, heating element, or some other method to raise flue gas temperature, such as adjustments to the waste heat recovery boiler to send more heat to the baghouse. Adjustments to the waste heat recovery boiler would reduce steam production but would be more cost effective than installing an afterburner system to reheat the flue gas. Typical Teflon-coated fiberglass bags in the baghouse can withstand temperatures up to 500°F. This location is also the "cleanest" compared to the other locations because the baghouse filters a majority of the PM. Placing the SCR downstream of the induced draft fan and the ammonia injection upstream of the induced draft fan can aide in uniform mixing of NOx and ammonia to increase removal efficiency and may be the most suitable location for a SCR with low temperature catalyst.

Initial BARCT Assessment and Considerations

Based on the annual average NOx emissions of 64 to 85 ppmv in the flue gas and 95% NOx emission reductions potential of the control technology assessed, staff determined a 5 ppmv NOx limit is technically feasible.

Costs and Cost-Effectiveness Analysis

LoTOx™ with Scrubber Costs

Tesoro provided cost estimates for total install cost of the LoTOx™ system at $117 million. Details of cost includes labor, downstream waste effluent treatment system, ozone generation system, water supply system, control systems, electrical, civil, mechanical, and structural work necessary to support the LoTOx™ installation. Estimates from the manufacturer were approximately $12 million and annual operating cost of $600,000. The manufacturer also estimates a 10% increase in water usage for the LoTOx™ system. Staff estimated installation costs to be 4.5 times ($54 million) of the capital cost based on the recommendation by Norton Engineering Consultants (NEC) in the 2015 BARCT assessment. Staff estimated the total installed cost for the LoTOx™ system to be $66 million. However, staff's estimates did not include a waste effluent treatment system. Staff's assumption that Tesoro's estimate includes all necessary costs for the LoTOx™ installation, so Tesoro's provided total installed cost estimate of $117 million and annual operating cost of $1.4 million was used to determine cost effectiveness.

UltraCat™ Costs

Tesoro provided process parameters to Tri-Mer, the manufacturer of UltraCat™, Tri-Mer assessed the information provided and estimated the capital cost for the UltraCat™ system to be $8.2 million with a total installed cost of approximately $50 million dollars. Tri-Mer estimated the annual operating cost to be approximately $2 million. The cost provided by the manufacturer includes any electrical expansion required by the project to accommodate the new UltraCat™ system. Staff estimated installation cost to be 4.5 times ($36.9 million) of the capital cost based on the recommendation by Norton Engineering in the 2015 BARCT assessment. The total installed cost is estimated to be $45.1 million; staff also applied a contingency factor of 1.2 to the present worth value to account for labor rates in California. Staff's estimation is within range of Tri-Mer's quoted total installed cost of approximately $50 Million.

SCR Costs

Cost estimates for SCR systems provided by vendors and range anywhere from $5 million to $8 million based on a five-year catalyst life, not including installation costs. The quotes provided from vendors are generalized estimates which may not reflect California structural codes or site-specific constraints of the facility. Staff estimated capital installation cost to be 4.5 times ($36 million) of the capital cost based on the recommendation by Norton Engineering in the 2015 BARCT assessment. Staff's estimate for total installed cost to be $44 million and applied a contingency factor of 1.2 to the present worth value to account for labor rates in California. During our initial meeting on September 28, 2018, the facility stated that they explored NOx control options and estimates for a SCR system were approximately $60 million due to the complexity and space restraints. Staff estimated annual operating cost to be $458,000, based on the annual operating costs reported in the survey for a SCR installed on a gas turbine. Gas turbine was chosen because flue gas flow rate is similar to that of the calciner. Staff also included the additional cost required to fuel the duct burner that will heat the flue gas to the appropriate temperature for the low-temperature catalysts and the total annual operating cost considering the added fuel cost, as tabulated in the following tables.

Table C-6. Estimated Cost for Additional Annual Fuel Cost

Estimated Additional Annual Fuel Cost	
Duct Burner fuel consumption	4,000 MMscf/year
Natural Gas cost in California	$7,600/MMscf
Total Fuel Cost	$4000 × 7,600 = $30,400

Table C-7. Estimated Annual Operating Cost of Duct Burner

Annual Operating Cost Reported for Turbine SCR	Estimated Additional Annual Fuel Cost	Estimated Annual Operating Cost
$427,000	$30,400	$458,000

The emission reductions for each of the three technologies is estimated to be 0.68 tons per day of NOx reduced based on representative year 2017 as reported by the facility. The table below summaries the cost and cost-effectiveness of each technology.

Table C-8. Cost and Cost-effectiveness Summary

Staff Cost Estimates			
Control Technology	LoTOx™	UltraCat™	SCR
Capital Costs (1)	$12,000,000	$8,200,000	$8,000,000
Installation Costs (2)	$54,000,000	$36,900,000	$36,000,000
Total Installed Cost	$66,000,000	$45,100,000	$44,000,000
Annual Operating Cost	$600,000	$2,000,000	$458,000[6]
PWV (3)	$75,373,248	$76,344,160	$51,154,913
Contingency Factor (4)	1.2	1.2	1.2
PWV with contingency factor	$90,447,897	$91,612,992	$61,385,895
Cost Effectiveness (5)	**$15,000**	**$15,000**	**$10,000**
Facility Cost Estimates			
Total Installed Cost	$117,000,000	–	$60,000,000
Annual Operating Cost	$1,354,625	–	$458,000
PWV (3)	$138,162,060	–	$67,154,913
Contingency Factor	Included in estimate	–	Included in estimate
Cost Effectiveness (5)	**$22,000**	–	**$11,000**

(1) Equipment cost estimation provided to staff by technology manufacturer. Cost in 2018-dollar year.
(2) Assumed installation cost to be 4.5 times capital cost based off Norton Engineering's recommendation in 2015 BARCT assessment at facility due to space constraints.
(3) PWV = Capital Costs + (15.62×Annual Operating Cost)
(4) Contingency factor to account for Senate Bill 54 requiring California refineries to hire unionized labor.
(5) Cost Effectiveness calculated using 25-year life
(6) Estimation based on annual operating cost of SCR for gas turbine and includes cost of supplemental fuel required to reheat flue gas if required (~4,000 MMSCF/year at $7,600/MMscf)

Proposed BARCT Limits

After consulting with the NOx control technology manufacturers, reviewing facility data, and considering challenges and costs for implementing the technology, South Coast AQMD staff concludes 5 ppmv NOx concentration is technically feasible at the stack. The outlet NOx is approximately 64 to 85 ppmv (annual average from survey data) and the control technologies can achieve 95 percent NOx reduction leaving approximately 3.2 - 4.25 ppmv NOx remaining. Staff recommends setting the BARCT level to a long-term limit of 5 ppmv NOx at three percent oxygen with a 365-day rolling averaging time. Staff recommends the long-term averaging time due to specific challenges at the coke calciner including, NOx emissions are feed dependent and variable; the coke calciner is a process unit and not an individual piece of combustion equipment; if a NOx excursion were to occur and an operational adjustment made, the response time may not be seen for several hours; and multiple pollutants need to also be addressed. To ensure short-term NOx limits also remain low, staff is also proposing a short-term limit of 10 ppmv at three percent oxygen with a 7-day rolling average. This short-term limit will account for process variations in day-to-day operation of the coke calciner. NOx control technologies such as LoTOx™, SCR, and UltraCat™ are commercially available and it is technically feasible and cost-effective to achieve the proposed levels. The following table summarizes the proposed BARCT NOx limits for the coke calciner. Post-combustion control was the only NOx control technology identified, so an incremental cost-effectiveness was not calculated as all three options are cost-effective to reach the same BARCT NOx limit.

Table C-9. Proposed BARCT Limits

	NOx limit (ppmv at 3%)	Averaging Time (Rolling)	Control Technologies	Cost Effectiveness ($/ton removed)	Emission Reductions (tpd)
Coke Calciner	5	365 day	LoTOx™, SCR, UltraCat™	$10,000 – $23,000	0.68
	10	7 day			

APPENDIX D FLUID CATALYTIC CRACKING UNITS

Fluid Catalytic Cracking Units

There are five petroleum crude refineries that operate five FCCUs in the South Coast AQMD: TORC, Chevron, Tesoro, Phillips 66, and Ultramar. The initial BARCT Assessment was presented in Working Group Meeting #2 on June 14, 2018 and completed and presented during Working Group Meeting #11 held on May 21, 2020. A reassessment to address units with existing controls and outliers was presented at Working Group Meeting #21. The reassessment was based on facility revised cost data. A brief description of the process is presented below.

Process Description

An FCCU converts heavy gas oils from the distillation process into more valuable gasoline and lighter products. A schematic of the process is shown in Figure 1. The process uses a very fine catalyst that behaves as a fluid when aerated. The fluidized catalyst is circulated continuously between a cracking reactor and a catalyst regenerator which transfers heat from the regenerator to the incoming feed going in the reactor. The cracking reaction is endothermic, and the regeneration reaction is exothermic. The fresh gas oil feed is preheated by heat exchangers to a temperature range of 500°–800°F and enters the FCCU at the base of the feed riser where it is contacted with the hot regenerated catalyst along with injected steam. The heat from the catalyst vaporizes the feed and raises it to the desired reaction temperature. The mixture of catalyst and hydrocarbon vapor travels up the riser into the reactor. The cracking reaction starts in the feed riser and continues in the reactor. Average reactor temperatures are in the range of 900°–1,000°F. As the cracking reaction progresses, the catalyst surface is gradually coated with coke, which deactivates the catalyst and reduces its efficiency. The cracked hydrocarbon vapors are routed overhead to a distillation column for separation into various products, the oil remaining on the catalyst is removed by steam stripping before the spent catalyst is cycled back into the regenerator.

In the regenerator, spent catalyst is reactivated (regenerated) by burning the coke off the catalyst surface. The regenerated catalyst is generally steam-stripped to remove adsorbed oxygen before being cycled back to the reactor. The regenerator exit temperatures for catalyst are about 1,200°–1,450°F. The regenerator can be designed and operated to either partially burn the coke on the catalyst to a mixture of carbon monoxide (CO) and carbon dioxide (CO_2), or completely burn the coke to CO_2. The regenerator temperature is carefully controlled to prevent catalyst deactivation by overheating and to provide the desired amount of carbon burn-off. This is done by controlling the air flow to give a desired CO_2/CO ratio in the exit flue gases or the desired temperature in the regenerator. The flue gas containing a high level of CO is routed to a supplemental fuel fired CO boiler if needed to completely burn off the CO to CO_2. All FCCUs in the South Coast AQMD are currently operated in complete burn mode; only two of the FCCUs have CO boilers and are used as waste heat recovery devices without any supplemental fuel. However, the CO boilers are equipped with low NOx burners capable of supplemental firing on refinery gas or natural gas.

The FCCU is a major source of SOx, NOx, PM_{10}, $PM_{2.5}$, as well as ammonia (NH_3), hydrogen cyanide (HCN) and other pollutants in the refinery and are formed during the regeneration cycle. PM is formed when some of the catalyst is lost in the form of catalyst fines. Approximately 90 percent of the NOx generated from the FCCUs are from the nitrogen in the feed that is accumulated in the coke which is burned-off in the regenerator. This portion of the NOx is called “fuel” NOx. “Fuel” NOx is a combination of nitric oxide (NO), nitrogen dioxide (NO_2), and nitrous oxide (N_2O). The remaining 10 percent of the NOx generated from the FCCUs are “thermal” NOx which is generated in the high temperature zones in the regenerator, and “prompt” NOx generated from the reaction between nitrogen and oxygen in the combustion air. The NOx emissions from the FCCU are typically controlled with DeNOx additives, selective catalytic reduction (SCR), and LoTOx™ scrubbers.

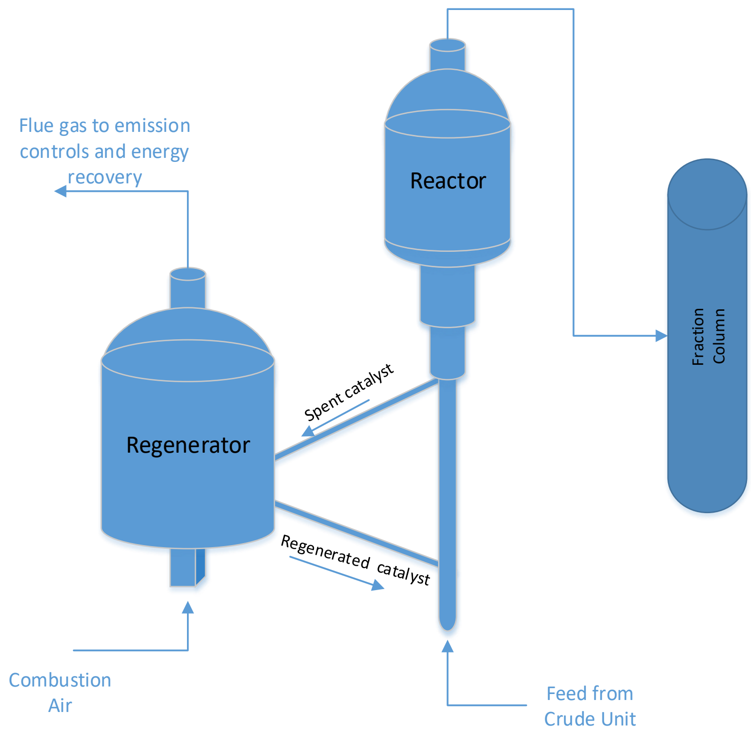


Figure D-1. Simplified Schematic of FCCU Process

BARCT Assessment

Assessment of South Coast AQMD Regulatory Requirements

Table D-1. South Coast AQMD Rules NOx Limits

Refinery Rule Limits and Assessments		
	2005 RECLAIM BARCT	2015 RECLAIM BARCT
Petroleum Refining, FCCU	85% reduction for FCCU and CO Boiler	2 ppmv at 3% O_2, dry

Assessment of Emission Limits of Existing Units

As shown in the table below, the total NOx emissions from the five FCCUs located in the South Coast AQMD are 0.83 tons per day.

Table D-2. 2017 NOx Emissions for FCCUs

Unit	Number of Units	2017 NOx Emissions (tpd)	Outlet NOx at 3% O_2 (ppmv)
FCCU	5	0.83	1.2 to 32.4

All five FCCUs operate below 40 ppmv NOx on annual basis. Ammonia limits on permit are 10 ppmv. Three FCCUs currently have SCRs in operation since 2000, 2003, and 2008. For these three FCCUs with SCRs, the outlet NOx concentrations range from 1.23 to 10.34 ppmv. One of the FCCU currently operates at a level under 2 ppmv NOx (as per permit conditions) on annual basis. As demonstrated FCCU's SCR, 2 ppmv NOx is a level of achieved-in-practice. At normal operations, the inlet NOx concentrations to the SCR range from 40 to 80 ppmv, and the outlet NOx concentrations are typically below 2 ppmv. The SCR can have three catalyst layers, but only two layers are in operation and still achieve 95 percent control efficiency. Typical catalyst life for this FCCU is approximately 5 to 6 years per SCR catalyst vendors. However, SCR catalysts could be replaced at much longer time intervals, such as 15 years or more. The other two FCCUs currently operate with no NOx controls and permit limits vary from 40 to 89 ppmv NOx. The outlet NOx concentrations are 14 to 32 ppmv.

Assessment of Other Districts NOx Rules and Limits

Staff assessed other rules and regulations outside the South Coast jurisdiction that regulate sources similar to FCCUs, which is summarized in the following table.

Table D-3. Other Air Districts NOx Rules and Limits for FCCUs

Bay Area Air Quality Management District	
Regulation 9-10-307 – Refinery NOx Emission Limit for CO Boilers	
NOx Limit – Operating Day	**NOx Limit – Calendar Year**
125 ppmv at 3% O_2, dry	85 ppmv at 3% O_2, dry
Texas Commission on Environmental Quality	
Title 30, Part 1, Chapter 117, Subchapter B, Division 3, Rule §117.310 – Emission Specifications for Attainment Demonstration	
Description	**NOx Emission Limit (one of the following)**
FCCU (including CO boilers, CO furnaces, and catalyst regenerator vents)	40 ppmv at 0% O_2, dry basis
	90% NOx reduction of the exhaust concentration used to calculate the daily NOx emissions

Assessment of Pollution Control Technologies

Several commercial NOx control technologies for FCCUs are available including DeNOx, SCR, and LoTOx™ with wet scrubber. The most effective form of NOx control for FCCUs are post-combustion control technologies which can achieve up to 95 percent NOx reductions.

DeNOx Additive or Combustion Promoter

DeNOx is added to the regenerator as part of the catalyst blend and can reduce NOx up to 45 percent. The reduction efficiency is dependent on the configuration and design of the FCCU and the need for combustion promotion. Some refiners require an additive in the circulating catalyst inventory that will promote the combustion of CO in the dense phase of the regenerator bed to avoid “after burn”. Traditional CO combustion promoter are Platinum-based that have an unwanted side effect of producing more NOx. DeNOx additives are non-platinum-based combustion promoters that raise the NOx levels less that platinum-based promoters or without promoters.

LoTOx™

LoTOx™ with wet gas scrubber (WGS) is a is post-combustion control technology that utilizes ozone with a wet gas scrubber to remove NOx and other pollutants, such as SOx and PM. The advantage of the LoTOx™ system is the multipollutant emission reductions that can be utilized at locations where space is an issue. A potential drawback of LoTOx™ is the maximum operating temperature of 325°F. FCCU regenerator flue gas temperatures are over 1,200°F; therefore, , a quench system will be required upstream of the LoTOx™ system to lower the flue gas temperature.

SCR

SCR is another flue gas treatment option that can achieve up to 95 percent NOx reduction. Three FCCUs within the South Coast AQMD use SCR for NOx control, one is performing at 2 ppmv at 3% O_2 based on a 365-day average, the other two are performing below 10 ppmv at 3% O_2 based on a 365-day average. SCR is proven NOx reduction technical for FCCUs. One FCCU in the South Coast AQMD is achieving the NOx limit of 2 ppmv with a SCR and another facility is in the process of constructing an SCR for a FCCU to meet the proposed 2 ppmv NOx limit.

Initial BARCT Assessment and Considerations

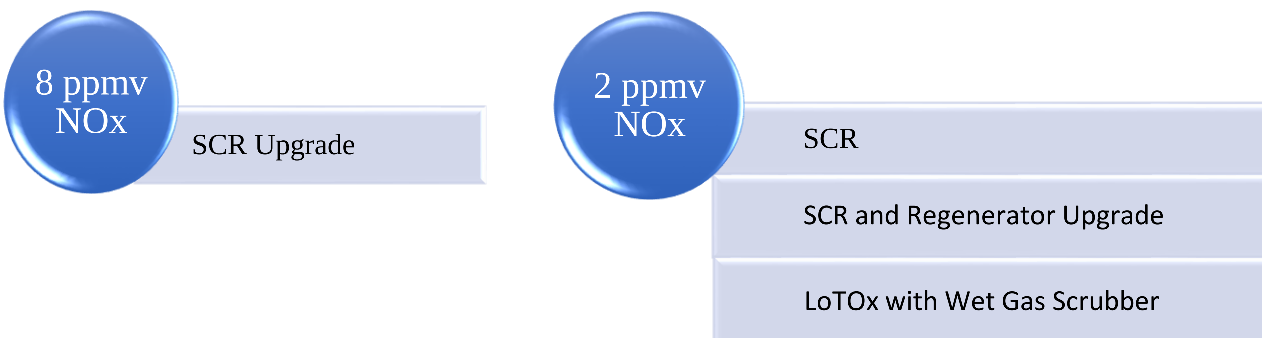
Based on the current performance of FCCUs with existing SCRs, reviewing current emission levels of existing FCCUs, and consulting with the NOx control technology manufacturers, staff concludes that a BARCT NOx limit of 2 ppmv at 3% O_2 NOx BARCT is technically feasible.

Costs and Cost-Effectiveness Analysis

Staff evaluated cost-effectiveness for all FCCUs that are not achieving the proposed 2 ppmv NOx limit. Facilities initially provided two capital cost estimates, $57 million and $19.5 million, that were used in the Total Installed Cost (TIC) estimation back in 2018. With these two data points, staff estimated costs for other units by scaling up the cost based on the flow rate. Annual average operating and maintenance cost (AC) was estimated based on the annual average catalyst replacement cost that facilities provided in the survey. The estimated AC is about 0.3 percent of the TIC for a new SCR installation. From there, staff assumed AC to be 0.5 percent of the TIC estimates for the control device, which is consistent with the boilers and heaters annual operating cost estimates. Staff used the Discounted Cash Flow (DCF) method using a 25-year equipment life and a four percent interest rate. The cost-effectiveness estimated at 2 ppmv NOx is $37,000 per ton of NOx reduced with a potential NOx reduction of 0.67 tons per day. In March 2021, staff allowed facilities to submit revised cost estimates based on refined engineering cost evaluations for their respective FCCUs. One refinery provided a cost estimate for a LoTOx™ system to achieve the proposed 2 ppmv NOx limit at a cost of $220 MM. two facilities provided revised cost of $1MM and $3MM for SCR upgrades to achieve 8 ppmv due to technical feasibility issues of achieving the proposed BARCT of 2 ppmv. One facility stated that they would have to replace their entire FCC regenerator along with a brand-new SCR at a cost of over $200MM to achieve the proposed BARCT limit of 2 ppmv.

Proposed BARCT Limits

Refinery stakeholders raised a concern over the technical feasibility and cost effectiveness for units with existing SCRs and their ability to achieve proposed BARCT limit of 2 ppmv. Initially staff assumed that those FCCUs with existing SCRS would only require an SCR upgrade to meet the proposed BARCT limit of 2 ppmv. Two refineries stated that based on further engineering evaluation, it is not technologically feasible to upgrade their existing SCRs to achieve less than 5 ppmv. In order to achieve the 2-ppmv, a brand-new SCR will need to be installed which would require demolition of the existing SCR, major reconfiguration, re-engineering, and re-design of the existing unit. In addition, major infrastructure modifications to the unit will be needed to accommodate the brand-new SCRs. Cost to replace the SCR are substantially higher than an upgrade and thus it is more cost-effective and feasible to upgrade existing units to achieve 8 ppmv NOx. Based on the revised cost and information from the refineries, staff reassessed the cost-effectiveness for FCCUs to meet 2 ppmv and 8 ppmv. In this category, two units are without NOx controls, one unit is in process of installing a SCR designed for 2 ppmv, three units with NOx controls, one unit performing well below 2 ppmv (annual average). Two units with SCR would need SCR replacement and new regenerator to achieve 2 ppmv and upgrades to existing SCR to achieve 8 ppmv. 8 ppmv will impact two refineries with existing SCRs and 2 ppmv will impact two refineries without any NOx controls – one refinery is currently in the process of constructing a SCR that is designed to achieve and meet the proposed BARCT of 2 ppmv.



Since some facilities did not provide costs for a brand-new SCR installation, staff estimated SCR total installed costs (TIC) based on vendor quote for a similar sized FCCU at a refinery. To estimate SCR cost, staff also applied the following:

- Increased cost by a factor of 4.5 for installation costs
- Increased cost by 20% to account for SB54 (requires refineries to hire unionized labor)
- Included 2 times retrofit factor to address space constraints -maximum multiplier in U.S. EPA cost model

FCCU Category Cost estimates

As mentioned earlier, one refinery provided cost for LoTOx™ system that can achieve multi-pollutant emission reductions (NOx, SOx, and PM) which costs considerably more than a SCR system. Since only NOx reductions of the three pollutants are required for 1109.1, staff evaluated LoTOx™ in achieving both NOx and SOx reductions and SCR for NOx reductions only. Below is the cost-effective analysis for the one refinery and potential control option pathways that they may choose.

Table D-4. Cost Effectiveness for FCCU

	Multi-Pollutant Scrubber	SCR
Estimated Present Worth Value	$218 MM	$76 MM
Emission Reductions (Lifetime tons)	NOx: 2,071	NOx: 2,071
	SOx: 2,027	
Cost Effectiveness	$46,000	$24,000

Based on the cost provided by the facilities, the LoTOx™ system is cost-effective at $46,000 if the facility choses it as a control option to meet the proposed BARCT limit of 2 ppmv.

Based on the revised cost data staff received from the refineries, 2 ppmv is not cost effective for all units in the FCCU category due to the high-cost effectiveness of two units currently equipped with NOx control. These two units have high cost to replace the existing control or modify the existing FCCU to achieve 2 ppmv. In addition, these two units are considered cost outliers due to the high cost and low emission reductions associated with achieving 2 ppmv from current operating levels. These two outlier units are currently performing near or below 10 ppmv based on a 365-day average. However, it is cost-effective for these outliers to upgrade or improve efficiency to achieve 8 ppmv. For units without any existing NOx control, it is cost-effective to add NOx controls to achieve 2 ppmv. In addition, the proposed rule will allow a 365-day rolling average to ensure the low levels can be met even with some operating variability.

Staff reassessed:

- The cost-effectiveness and incremental cost-effectiveness of the two cost outlier units for achieving a conditional limit at 8 ppmv and BARCT limit of 2 ppmv
- The cost-effectiveness of the remaining two units with the outlier units removed to achieve 2 ppmv

The table below provides cost-effectiveness for the FCCU category. Cost-effectiveness of SCR upgrades for units with existing SCRs (outliers) was calculated, then cost-effective for all FCCs were calculated along with the incremental cost-effectiveness. Finally, cost-effectiveness for units without existing controls were calculated. An incremental cost-effectiveness was not conducted for units without existing controls because no other control technology was identified.

Table D-5. Proposed BARCT Limits and Cost-Effectiveness

NOx Limit (ppmv at 3%)	Averaging Time (Rolling)	Control Technologies	Cost-Effectiveness ($/ton NOx Removed)	Emission Reductions (tpd)
FCCUs with Existing SCRs (Outliers)				
8	365 day	SCR Upgrades	$12,000	0.06
10	7 day			
All FCCUs Including Outliers				
2	365 day	New SCR or New Regenerator	$108,000	0.32
5	7 day			
Incremental Cost-Effectiveness (8 ppmv to 2 ppmv) Including Outliers				
2	365 day	New SCR or New Regenerator	$127,000	0.25
5	7 day			

Table D-6. Incremental Cost-Effectiveness (8 ppmv to 2 ppmv) including outliers

NOx Limit (ppmv at 3%)	Averaging Time (Rolling)	Control Technologies	Incremental Cost Effectiveness	Emission Reductions (tpd)
8 ppmv to 2 ppmv	365 day	New SCR	$127,000	0.25

Table D-7. Cost Effectiveness for FCCU after Excluding Outliers

	NOx limit (ppmv at 3%)	Averaging Time (Rolling)	Control Technologies	Cost Effectiveness ($/ton removed)	Emission Reductions (tpd)
Excluding Outliers					
FCCU	2	365 day	New SCR	$24,000	0.36
	5	7 day			

APPENDIX E GAS TURBINES

Gas Turbines

There is a total of twelve gas turbines operating at refineries in the South Coast AQMD; Gas turbines in this category range from 342 MMBtu/hr (34 MW) to 986 MMBtu/hr (83 MW). Nine of 12 gas turbines have duct burners and are in combined-cycle operation; the remaining three gas turbines have no duct burners and operate with heat recovery only. Duct burners are typically used in combined cycle and cogeneration installations to boost exhaust gas temperature upstream of the HRSG when needed. Gas turbines and duct burners emissions are controlled by post-combustion control system such as Selective Catalytic Reduction (SCR); all twelve gas turbines are equipped with SCRs. The oldest installed in in the late 1980's and newest in 2017. Out of the twelve gas turbine units, two units are entirely fired with natural gas and ten units are fired with other fuels (e.g., refinery fuel gas or refinery mixed gas). In the mixed fuel turbines, refinery gas is used as primary fuel and natural gas as secondary fuel. One refinery has the capability to fire using propane as part of the refinery gas/natural gas mix.

Process Description

Gas turbines are used in refineries to produce electricity and steam. Frame gas turbines are exclusively used for power generation and continuous base load operation ranging up to 250 MW with simple-cycle efficiencies of approximately 40% and combined-cycle efficiencies of 60%. Aeroderivative gas turbines are adapted from aircraft engines. These turbines are lightweight and more efficient than frame turbines however the largest units are available for up to only 40-50 MW. The figure below shows a general scheme of a combined cycle gas turbine operation. Ambient air is drawn, compressed, and mixed with fuels (e.g., natural gas, refinery fuel gas, refinery mixed gas, butane) and ignited in the combustor. High temperature exhaust is produced and used to rotate one or more shafts. NOx in the exhaust flue gas is treated by catalytic reduction. Passing through the heat recovery boiler or HRGS, the thermal energy of the flue gas is recovered in the form of steam that is then used to turn an additional steam turbine.

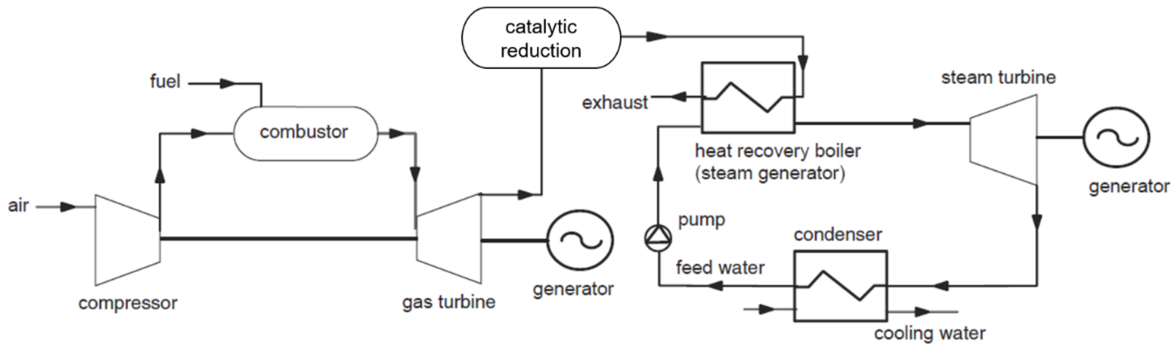


Figure E-1. Combined Cycle Gas Turbine Diagram

BARCT Assessment

Assessment of South Coast AQMD Regulatory Requirements

Table E-1. South Coast AQMD Rules NOx Limits

Refinery Rule Limits and Assessments			
	2005 RECLAIM BARCT	**2015 RECLAIM BARCT**	**Rule 1134 (Combined Cycle)**
Refinery Gas Turbines	–	2 ppmv at 15% O_2, dry	2 ppmv at 15% O2, dry (Natural Gas)

Assessment of Emission Limits of Existing Units

The two gas turbines operating with natural gas are achieving 2 ppmv NOx limit in practice. The total NOx emissions from the other ten gas turbines (with refinery gas) located in the South Coast AQMD are 0.83 tons per day, as shown in the table below.

Table E-2. 2017 NOx Emissions for Gas Turbines

Unit	Number of Units	NOx Control	2017 NOx Emissions (tpd)	Outlet NOx at 15% O_2 (ppmv)
Gas Turbines with Natural Gas				
Gas Turbine	2	SCR	0.03	1.1 to 1.9
Gas Turbines with Refinery Gas				
Gas Turbine	10	SCR	1.38	2.8 to 6.4
Total			**1.41**	

Assessment of Other Districts NOx Rules and Limits

Table E-3. Bay Area AQMD NOx Rules and Limits for Gas Turbines

Bay Area AQMD					
Regulation 9, Rule 9 - Limits Emissions of NOx from Stationary Gas Turbines					
	Turbine Heat Input Rating (MMBTU/hr)		**Natural Gas (ppmv)**	**Refinery Fuel Gas, Waste Gas or LPG (ppmv)**	**Non-Gaseous Fuel (ppmv)**
Emission Limits, General	> 50 – 150	No retrofit	42	50	65
		Water inject/steam injection	35	50	65
		Dry Low Nox	25	50	65
	> 150 – 250		15	15	42
	> 250 – 500		9	9	25
	> 500		5	9	25
Emission Limits, Low Usage	50 – 250		42	N/A	65
	> 250		25	N/A	42

Table E-4. Texas CEQ NOx Limits for Gas Turbines

Texas Commission on Environmental Quality	
Title 30, Part 1, Chapter 117, Subchapter B, Division 3, Rule §117.310 – Emission Specifications for Attainment Demonstration	
Stationary Gas Turbine Rating (MW)	**NOx Emission Limit (ppmv)**
>10	29
1 to 10	135
<1	233

Assessment of Pollution Control Technologies

Gas turbine units subject to PR 1109.1 are fired with natural gas or other fuels (e.g., refinery fuel gas). In conventional combustors, greater than 50 percent of NOx emissions are expected from refinery fuel gas. Refinery fuel gas burns at higher flame temperatures and thus, can increase NOx emissions over the NOx levels for natural gas that consists mainly of methane. Gas turbines with Dry-Low NOx (DLN) combustors can operate with stack gas NOx emission concentration as low as 9 ppmv but typically in the range of 9–25 ppmv at 15 percent O_2 without water or steam injection when operating on natural gas. DLN combustors can have approximately 10 percent greater NOx emissions when operating on refinery fuel gas.

Pre-Combustion Technologies

Dry Low-NOx or Lean Premix Emission Combustors (Natural Gas Turbines)

Prior to combustion, gaseous fuel and compressed air are pre-mixed, minimizing localized hot spots that produce elevated combustion temperatures and therefore, less NOx is formed. Atmospheric nitrogen from the combustion air is mixed with air upstream of the combustor at deliberately fuel-lean conditions. Approximately twice as much air is supplied as needed to burn the fuel. This excess air is a key to limiting NOx formation, as very lean conditions cannot produce the high temperatures that create thermal NOx. Using this technology, NOx emissions, without further controls, have been demonstrated at single digits (< 9 ppmv at 15% oxygen on a dry basis). The technology is engineered into the combustor that becomes an intrinsic part of the turbine design. Fuel staging or air staging is utilized to keep the flame within its operating boundaries. It is not available as a "retrofit" technology and must be designed for each turbine application.

Water or Steam Injection (Natural Gas Turbines)

Demineralized water is injected into the combustor through the fuel nozzles to lower flame temperature and reduce NOx emissions. Water or steam provides a heat sink that lowers flame temperature. Imprecise application leads to some hot zones, so NOx is still created. NOx levels in natural gas turbines can be lowered by 80% to 25 ppmv at 15% oxygen on a dry basis. Addition of water or steam increases mass flow through the turbine and creates a small amount of additional power. The addition of water increases carbon monoxide emissions and there is added cost to demineralize the water. Turbines using water or steam injection have increased maintenance due to erosion and wear are able to reduce NOx concentration to 5 to 7 ppmv at 3% oxygen on a dry basis. The burners are scalable for various sizes of boilers and heating units. The burners can be designed for retrofit or new installations. However, retrofits to existing gas turbines may require complex engineering and re-design.

Initial BARCT Assessment and Conditions

2015 BARCT Assessment and Norton Engineering report concluded that a 2 ppmv NOx limit is technically feasible for gas turbines in PR 1109.1 universe. Initial BARCT assessment for gas turbines subject to PR 1109.1 showed that combination of dry-low NOx (DLN) combustor and SCR can achieve 2 ppmv NOx limit with proper engineering and design. DLN combustors can achieve between 9 ppmv and 25 ppmv in gas turbines operating with natural gas and between 10 ppmv and 27.5 ppmv in gas turbines operating with refinery gas (i.e., about 10% higher NOx emissions compared with natural gas fired ones). Moreover, SCR can achieve about 95% NOx reduction in both types of gas turbines. Recent BARCT Assessments in Rule 1134 (Emissions of Oxides of Nitrogen from Stationary Gas Turbines) and Rule 1135 (Emissions of Oxides of Nitrogen from Electricity Generating Facilities) established 2 ppmv to be achievable for combined cycle gas turbines fired with natural gas.

The two gas turbines fired with natural gas have existing SCRs and CO catalysts with an average NOx removal efficiency of 94% by the existing SCRs. Both units currently achieving less than 2 ppmv NOx emissions. Subsequent to this analysis, staff received comments on a gas turbine with natural gas achieving a concentration level close to the proposed NOx limit and thus eligibility for a conditional limit. Staff was able to gather cost data for upgrades necessary for that unit close to the NOx limit to retrofit and meet the Table 1 NOx limit in the proposed rule. More specifically, there are four natural gas turbines at the affected facilities, of which two are achieving less than 2 ppmv NOx, including one that has a NOx permit limit of 2.5 ppmv. In order for the unit at 2.5 ppmv to meet the even lower NOx limit, the existing SCR would need to be replaced. All gas turbines operating with refinery gas have existing SCRs and CO catalysts with SCR NOx removal efficiency of 70 to 89 percent, catalysts age range between one and 12 years, and a catalyst beds range of 1 to 2. NOx removal efficiency can be improved in these units by SCR upgrade (e.g., ammonia injection grid, catalyst, additional catalyst beds) and there is a possibility of combustor upgrade between 10 to 27.5 ppmv. Stack test demonstrated that combination of DLN combustor and maximized SCR removal efficiency can technically achieve around 2 ppmv NOx. Since this initial analysis, staff received comments on the technical challenges for gas turbines fired with refinery gas to achieve 2 ppmv even with a retrofit. There are eight gas turbines at refineries that operate on refinery gas or mixed fuel achieving between 2.8 ppmv to 10 ppmv. One facility upgraded their existing SCR with the replacement with a state-of-the-art catalyst (verified by the vendor as best performing) on 2 units targeting 2 ppmv but are only achieving 3 ppmv. Refinery fuel gas has a higher heating value (HHV) and is more variable than natural gas, and HHV can result in higher NOx emissions. With the concern about technical feasibility, staff evaluated a 3 ppmv NOx limit for gas turbines fired with refinery gas since there are units operating around that level so achieved in practice.

Cost and Cost-Effectiveness Analysis

Cost-effectiveness assessment demonstrated that all existing gas turbines operating with natural gas are achieving 2 ppmv NOx limit in practice. To address the conditional limit, staff conducted a further cost-effectiveness analysis of the existing unit at 2.5 ppmv to determine if it is an outlier and whether the 2.5 ppmv would qualify as a conditional limit. As with the other conditional limit determinations, staff also had to evaluate the cost effectiveness of the remaining natural gas turbines to meet the Table 1 NOx limit. The cost for the SCR replacement was determined to be $9 million according to the U.S. EPA's SCR cost model in present worth value. As such, the cost effectiveness to reduce the NOx limit from 2.5 ppmv to 2 ppmv is $570,000 per ton of NOx reductions, and thus not cost effective, thus, qualifies as a conditional limit. For the remaining units to meet the 2 ppmv with an SCR replacement cost of $12-13 million from the U.S. EPA SCR cost model, it was concluded to be cost effective at $15,400 per ton of NOx reductions.

Staff evaluated cost-effectiveness for all gas turbines operating with refinery gas using the U.S. EPA cost model with a 20% increase for labor costs and excluded the modified cost curve best applicable to the case of heaters and boilers. Assessments established SCR upgrades as the most cost-effective option to achieve 2 ppmv NOx limit for these units. Staff also conducted cost-effectiveness analysis for these units based on associated costs with new SCR installation as a worse case cost assumption. To meet a 3 ppmv NOx concentration limit, the unit would still need control NOx efficiency 95 percent which can be done with an SCR or a dry low-NOx (DLN) combustor. Cost estimates for SCR range from $11 to $26 million and for DLN approximately $10 million. The cost effectiveness to meet the 3 ppmv from current NOx levels for refinery gas turbines was calculated to be $19,300 per ton NOx reduced but the incremental cost effectiveness to drive these units down to 2 ppmv was $74,300 per ton NOx reduced, so 2 ppmv was determined to be not cost effective.

Proposed BARCT Limits

After consulting with the South Coast AQMD-hired contractors, reviewing facility data, and considering challenges and costs for implementing the technology, South Coast AQMD staff concludes meeting a 2 ppmv NOx concentration at the stack is technically feasible and cost effective with firing natural gas and as explained above, with a conditional limit of 2.5 ppmv. For gas turbines fueled with refinery gas, the technically feasible and cost-effective limit of 3 ppmv is being proposed. Since the NOx concentrations in the flue gas into the existing SCRs are not reported in the survey, it is difficult to tell the level of NOx removal efficiency of existing SCRs. However, a typical SCR can remove up to 95 percent of NOx emissions when properly engineered and designed on the SCR performance. Existing SCRs may warrant further optimization and tuning of ammonia injection grid to improve local mixing and ammonia distribution at the SCR catalyst face. Staff recommends setting the BARCT level to 2 ppmv NOx at 15 percent O_2 for the natural gas turbines and 3 ppmv NOx at 15 percent O_2 for the other fuels (e.g., refinery fuel gas) turbines. SCR and DLN combustor NOx control technology is commercially available, technically feasible, and cost effective to achieve the proposed level.

Table E-5. Proposed BARCT Limits

	NOx limit (ppmv at 15%)	Averaging Time (Rolling)	Control Technologies	Cost Effectiveness ($/ton removed)	Emission Reductions (tpd)
Gas Turbines (Natural Gas)	2	24 hours	SCR	$15,400	0.18
Gas Turbines (Other Fuels)	3	24 hours	SCR or DLN Combustor	$19,300	0.30

Staff is also proposing to include an alternative NOx limit for gas turbines operating on refinery gas during periods of natural gas curtailment, which is a shortage in the supply of pipeline natural gas, due solely to supply limitations or restrictions in distribution pipelines by the utility supplying the gas, and not due to the cost of natural gas. These events are infrequent but can impact local refineries. In the past year, Texas experienced a super cold winter causing pipes to freeze coupled by power outages causing a sudden demand for natural gas and thus natural gas curtailment locally. This can be problematic for refineries who supplement their refinery fuel with natural gas, and if not available, they must substitute with other fuels (e.g., propane or butane). Unfortunately, the higher heating value of the alternative fuels results in higher NOx emissions. In order to address this potential issue, staff reviewed CEMS data during this winter's natural gas curtailment and is proposing a 5 ppmv NOx limit during periods of natural gas curtailment. Since there is only one proposed NOx limit for each category of turbines, an incremental cost-effectiveness calculation could not be performed

APPENDIX F SULFUR RECOVERY UNITS/TAIL GAS INCINERATORS

Sulfur Recovery Units/Tail Gas Incinerators

There is a total of sixteen Sulfur Recovery Units/Tail Gas (SRU/TG) Incinerators operating in the South Coast AQMD, thirteen without stack heaters and three with stack heaters. The BARCT assessment was initiated and presented in Working Group Meeting #2 on June 14, 2018 and completed and presented during Working Group Meeting #10 held on February 18, 2020.

Process Description

Sulfur recovery typically refers to the conversion of hydrogen sulfide (H_2S) to elemental sulfur. H_2S is a byproduct of refining and processing high-sulfur crudes slates. Amine treating units are used to recover H_2S from various sour gas streams at the refineries. The acid gases from the amine units are sent to sulfur plant for conversion to elemental sulfur. The most common conversion method used in the South Coast Air District is Claus process which typically recovers 95 to 97 percent of the hydrogen sulfide in the feed stream. The SRU (Claus unit) consists of a reactor and series of converters and condensers. Approximately 95% of sulfur from the gaseous streams is recovered after passing through the SRU. The tail gas is then sent to an amine absorption unit, or diethanol amine (DEA), SCOT, Wellman-Lord, and FLEXSORB to absorb and recover the remaining sulfur. Approximately 99% or the remaining sulfur is absorbed and recovered after the amine units. An SRU/TG incinerator is typically located downstream of a Claus where any residual H_2S in the tail gas is oxidized to SO_2 before being emitted into the atmosphere. The refinery SRU/TG Incinerator are classified as major sources of NOx and SOx. The downstream SRU/TG Incinerators runs at high excess O_2 and low combustion temperatures, so thermal NOx formation is minimal – NOx emissions from the SRU incinerators are the result of NOx concentration in the inlet gas stream.

BARCT Assessment

Assessment of South Coast AQMD Regulatory Requirements

Since the interception of the RECLAIM in 1993 until 2010, the South Coast AQMD did not set any BARCT standards for the SRU/TG. However, as part of the BARCT assessment, regulatory requirements for SRU/TG in the South Coast AQMD is shown in the table below. The 2015 RECLAIM BARCT NOx limit was determined 2 ppmv corrected to 3 percent oxygen.

Table F-1. South Coast AQMD Rules NOx Limits

Refinery NOx Limits and Assessments	
2015 RECLAIM BARCT	
Sulfur Recovery Units/Tail Gas Incinerator	2 ppmv NOx at 3% O_2, dry

Assessment of Emission Limits of Existing Units

As shown in the table below, the total NOx emissions from the SRU/TG Incinerators located in the South Coast AQMD are 0.43 tons per day. Currently no units have been retrofitted with post-combustion control and their annual average outlet NOx concentrations ranging from as low as 4 to 98 parts per million by volume, dry (ppmv), depending on the type of fuel fired and operating conditions. Three SRU/TG Incinerators have permit limits and are operating below their permit limits based on the annual average as reported in the survey.

Table F-2. NOx Emissions for SRU/TG Incinerators

Units	Number of Units	Size (MMBtu/hr)	2017 NOx Emissions (tpd)	NOx in Flue Gas @ 3% O_2 (ppmv)
SRU/TG Incinerator	19	10 to 100	0.43	4 to 98

Assessment of Other Districts NOx Rules and Limits

Table F-3. Other District NOx Limits

Texas Commission on Environmental Quality (TCEQ)	
Title 30, Part 1 Chapter 117, Subchapter B, Division 3, RULE §117.310	
Incinerators	NOx Emission Limit (ppmv*)
Incinerators (excluding vapor streams resulting from vessel cleaning routed to an incinerator, provided that fuel usage is quantified using good engineering practices)	27 ppmv (@3%, O_2, dry)
	80% reduction from the daily NOx emissions

Assessment of Pollution Control Technologies

Commercially available NOx control technologies for this category are LNB/ULNB, SCR, and LoTOx™. SCR is a post-combustion control technology that requires an optimal temperature window to achieve maximum reductions, thus a waste heat boiler may be necessary to reduce flue gas temperatures to SCR operating temperatures. This can add cost and additional space requirements. SCR can be designed to reduce 95% NOx emissions. One potential drawback of SCR for this application is the high SO_3 content in the flue gas which can lead to ammonium bisulfate fouling, making SCR impractical for this category. However, LoTOx™ operates at lower temperatures and is used in conjunction with a WGS to reduce NOx, and SOx. LoTOx™ with wet gas scrubber technology is a good candidate provided that space is available for equipment. The LoTOx™ system requires an ozone generation system on site and waste effluent treatment for the wastewater generated from the LoTOx™ process. Depending on the location of the facility, building a waste effluent treatment system may also not make the technology practical. Staff has not identified any location where post-combustion is used for controlling NOx. The most practical option for the category is custom designed LNB/ULNB upgrades which can be designed to reduce up to 80 percent NOx emissions (<30 ppmv) similar to the sulfuric acid plant furnaces. Several burner manufacturers have dedicated business divisions that specialize in this particular application.

Initial BARCT Assessment and Considerations

Based on the current flue gas NOx emissions of 58 to 100 ppmv in the flue gas and the fact that most post-combustion control can achieve greater than 95% NOx reductions, staff determined a NOx limit of 2 to 30 ppmv is technically feasible. These limits were used to assess the cost effectiveness.

Costs and Cost-Effectiveness Analysis

SCR Costs

Staff received one cost estimate from a facility for a SCR retrofit at a cost of approximately $60 MM for two units with common SCR. Cost estimate for the remaining units were determined as follows:

- SCR cost ~$45 per standard cubic feet of stack flow rate which was received from a SCR vendor
- Waste heat boiler at ~ $100,000 which is needed to cool the gas to SCR operating temperature
- Installation costs estimated at approximately 4.5 times capital cost (based on 2015 BARCT Norton Engineering recommendation)
- Operating and maintenance estimated to be approximately $150,000/year

Eight units exceed the 95% reduction to achieve 2 ppmv and would need to replace the burners, so staff included the cost of burners to achieve 2 ppmv – the burner cost curve was used to estimate cost. There were no units that needed burner upgrade to get to 5 ppmv. Despite being technically feasible to retrofit to 2 or 5 ppmv with SCR, it was not cost effective which is shown in the table below.

Table F-4. SCR Cost-Effectiveness

Cost-Effectiveness at 2 and 5 ppmv	
2 ppmv (SCR and ULNB)	5ppmv (SCR)
$107,000	$125,000

LoTOx™ Costs

Staff relied on 2015 BARCT assessment to estimate costs for LoTOx™ control technology with three data points and scaled costs up using 4% interest rate and created cost curve for total install and O&M costs. Eight units exceed 95% reduction to achieve 2 ppmv and would replace burners. Burner cost curve used to estimate cost. No unit needs to replace burners to achieve 5 ppmv. Similar to SCR, although it was technically feasible to retrofit to 2 or 5 ppmv with LoTOx™ technology, it was not cost effective as shown in the table below.

Table F-5. LoTOx™ Cost-Effectiveness

Cost-Effectiveness at 2 and 5 ppmv	
2 ppmv (LoTOx™ and ULNB)	**5ppmv (LoTOx™)**
$71,000	$65,000

ULNB Costs

Staff received additional cost in the from facilities which were used to revise the burner cost curve. The burner cost curve was used to estimate burner costs and the average cost was about $3.1 MM. However, the operating and maintenance costs was estimated to be about $2,000 per year. Nine units currently operating above 30 ppmv and need to retrofit. The ULNB technology is feasible, but it is also cost effective to retrofit SRU/TG Incinerator to 30 ppmv using ULNB technology as it is shown in the table below.

Table F-6. ULNB Cost-Effectiveness

Cost-Effectiveness at 30 ppmv
ULNB
$39,000

Proposed BARCT Limits

After consulting with the NOx control technology manufacturers, reviewing facility data, and the 2015 BARCT assessment, staff recommends setting a new BARCT level of 30 ppmv NOx for SRU/TG Incinerators based on burner technology which is technically feasible and cost effective. Nine units out of sixteen need to retrofit based on the new BARCT limit. Achieving 2 or 5 ppmv with SCR and LoTOx™ technologies were technically feasible but not cost-effective. The BARCT assessment for the 2015 RECLAIM shave concluded a 2 ppmv NOx limit was technically feasible and cost-effective. The NOx shave was to reduce emissions from RECLAIM facilities and staff only evaluated the higher emitting SRU/TG Incinerators. PR 1109.1 is a command-and-control rule, so staff had to evaluate each unit in the class and category. When all the units were assessed, neither 2 ppmv nor 5 ppmv was cost-effective. An incremental cost-effectiveness was not conducted because no other control technology was identified as cost-effective.

Table F-7. Proposed BARCT Limits

	NOx limit (ppmv at 3%)	Averaging Time (Rolling)	Control Technologies	Cost Effectiveness ($/ton removed)	Emission Reductions tpd
Sulfur Recovery Units/Tail Gas Incinerators	30	24 hours	LNB	$39,000	0.1

APPENDIX G FLARES AND VAPOR INCINERATORS

Flares and Vapor Incinerators

There is a total of fourteen units in the category, includes one flare and thirteen afterburners, vapor incinerators, and thermal oxidizers. The following BARCT assessment was initiated and presented in Working Group Meeting #3 on August 1, 2018 and completed and presented during Working Group Meeting #12 held on July 17, 2020. The following is the summary of the BARCT assessment.

Process Description

Flare

A flare is a control device that is utilized to control a VOC stream by piping it to a burner that combusts the VOC containing gases. Early flares were designed as elevated, candlestick-type flares that have an open flame with a specially designed burner tip, and auxiliary fuel to achieve nearly 98 percent VOC destruction. Complete combustion results in the conversion of all the VOCs to carbon dioxide and water but also results in emission of NOx, SOx, and CO. Open flares have a high rated capacity and long service life. They are low-cost, simple to use, and reliable but they are also noisy, emit smoke, heat radiation, and light. Open flares cannot be source tested due to the open flame and absence of a stack.

The new generation of ultra-low NOx flare utilizes a pre-mixed gas stream with air-assist combustion and is designed with an ULNB to decrease NOx and VOC emissions. These ultra-low NOx flares can achieve NOx emissions of less than 0.025 pounds per MMBtu. The technology has been available for almost a decade. There are two major manufactures of these ultra-low NOx flares. John Zink Hamworthy Combustion (John Zink) produces Zink Ultra Low Emissions (ZULE®) flare, which electronically control air-to-fuel ratio within the enclosed flare to provide more efficient destruction and less NOx emissions without an increase of CO emissions. The other ultra-low NOx flare is the Certified Ultra-Low Emissions Burner (CEB®) produced by the Aereon Corporation. It incorporates the premixing of gases and patented wire mesh burner technology that allows for more surface area, resulting in more efficient combustion and retention of heat, with a decrease of NOx emissions. Due to the added complexity in the design of the ultra-low NOx flares, some stakeholders have experienced reliability issues. This is especially true of the early generation flares installed that do not combust a constant gas flow. More recently, Perennial Energy has introduced an ultra-low NOx flare which guarantees 0.025 pounds of NOx per MMBtu and 0.06 pounds of CO per MMBtu. These flares have a smaller footprint and 100 percent stainless steel burners, and they use technology that involves automatic air fuel ratio controls with proprietary burner technology.

The flares subject to PR 1109.1 are not the same type as the refinery flares subject to Rule 1118. Rule 1118 flares are tall stacks equipped with a burner, used to destroy any excess gases produced by refineries, sulfur recovery plants, and hydrogen production plants. Flare systems are in operation all the time. Most of the time these systems are in standby mode, ready to combust gases as soon as they enter the flare. Flaring occurs to ensure safety during scheduled maintenance, the startup/shutdown of a process unit, or other activities where a refinery or related source can reasonably anticipate the need to dispose excess gases that cannot be safely recycled into the facility. Flaring also occurs to ensure safety during emergencies caused by equipment breakdown, power outage, or other upset beyond a refinery's control. The flares safely burn excess gases that could otherwise pose potential risks to workers, the community, or the environment. The following figure illustrate the applicability of each rule.

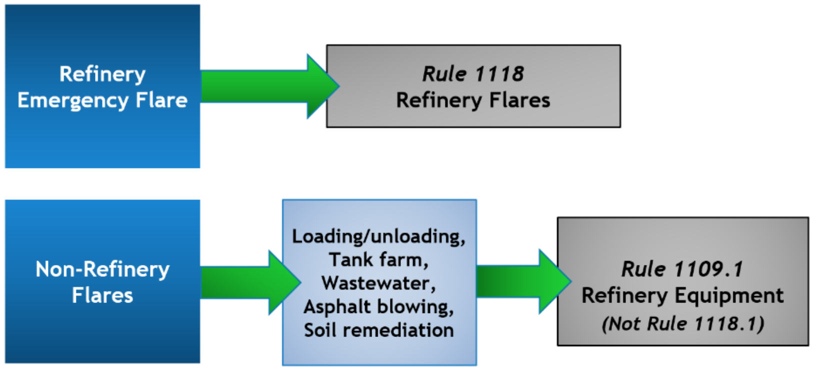


Figure G-1. South Coast AQMD Flare Regulations

Vapor Incinerator

Vapor Incinerators are one of the most proven methods to control VOCs emissions released form industrial sources by means of thermal destruction. The term "incineration" refers to an ultimate disposal method which is a thermal treatment of waste materials (solid, liquid, or gas) through a combustion process in the presence of oxygen. The combustion process increases the temperature of the material to higher than its auto-ignition point and maintains the high temperature for enough time to complete the combustion to carbon dioxide and water. Time, temperature, turbulence, and available oxygen are the basic design parameters for incinerators since they affect the efficiency of the combustion process. The terms "incinerator" and "oxidizer" are used interchangeably for thermal treatment of gaseous waste streams of VOCs and/or hazardous air pollutants (HAP).

There are two broad classes of oxidizers: thermal systems and catalytic systems. Thermal systems may include direct flame incinerators with no energy recovery, flame incinerators with a recuperative heat exchanger (Recuperative Thermal Oxidizers), or regenerative systems that operate in a cyclic mode to achieve high energy recovery (Regenerative Thermal Oxidizers). Catalytic systems are fixed-bed or fluid-bed systems which can provide energy recovery.

Thermal Oxidizers

The main part of the thermal oxidizer is a nozzle-stabilized flame which heats the waste gas as it passes through to its ignition temperature at which the combustion reaction rate (and consequently the energy production rate) exceeds the rate of heat losses, and therefore, any waste stream material mixture will burn. The mixture continues to react as it flows through the combustion chamber. The nozzle-stabilized flame is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. The reactor temperature is defined based on the required level of VOC control of the waste gas to be achieved and the residence time of the stream in the thermal combustion chamber dictates the reactor temperature.

Carbon dioxide and water are the most abundant elements in the exhaust gases from thermal oxidizers, however, the incineration of nitrogen-bound wastes at high temperatures in a thermal oxidizer generates high levels of nitrogen oxide emissions. Moreover, often auxiliary fuel (e.g., natural gas) must be added to the waste gas stream to help with raising its temperature to the desired levels if the combustion of VOCs in the stream is not enough to provide the temperature. Process adjustments such as using low-NOx burners or controls using reducing agents such as ammonia and urea-based scrubbers are effective to reduce the formation of nitrogen oxide in thermal oxidizers. The incoming waste stream and/or auxiliary air can be preheated in a recuperative heat exchanger using the effluent stream containing the products of combustion which could decrease auxiliary fuel requirements and improve energy efficiency.

BARCT Assessment

Assessment of South Coast AQMD Regulatory Requirements

Table G-1. South Coast AQMD Rule NOx Limits

NOx Limits and Assessments	
South Coast AQMD Rule 1147	
Incinerator, Afterburner, Remediation Unit, and Thermal Oxidizer	60 ppmv or 0.073 lb/MMBTU
South Coast AQMD Rule 1118.1	
Non-Refinery Flares	Replacement with 20 ppmv flare (0.025 lb/MMBtu) if throughput capacity > 5%

Assessment of Emission Limits of Existing Units

As shown in the table below, the total NOx emissions from the flare and vapor incinerators located in the South Coast AQMD are 0.05 tons per day. Currently no units have been retrofitted with post-combustion control and their annual average outlet NOx concentrations ranging from 9 ppmv to 134 ppmv corrected to 3 percent oxygen, depending on the type of fuel fired and operating conditions. Five vapor incinerators have permit limits and are operating below the permit limits.

Table G-2. NOx Emissions for Flares and Vapor Incinerators

Units	Number of Units	Size (MMBtu/hr)	2017 NOx Emissions (tpd)	NOx in Flue Gas @ 3% O_2 (ppmv)
Vapor Incinerator	13	1.2 to 60	0.05	9 to 134
Flare	1	1.09	0.0005	

Assessment of Other Districts NOx Rules and Limits

Table G-3. Other District NOx Limits

San Joaquin Valley Air Pollution Control District	
Rule 4311 – FLARES	
Type of Flare and Heat Release Rate in MMBtu/hr	**NOx Emission Limit (lb/MMBtu)**
Enclosed Flare	
Without Steam-assist	
< 10	0.0952
10 – 100	0.1330
> 100	0.5240
With Steam-assist	
All Sizes	0.068
Other Types of Flares	
Flares at Oil and Gas Operations or Chemical Operations	0.018
Flares at Landfill Operations	0.025
Flares at Digester Operations (Located at a Major Source)	0.025
Flares at Digester Operations (Not located at a Major Source)	0.060

Assessment of Pollution Control Technologies

As the units in this category are very small (1-30 MMBtu/hr) installing a SCR control technology will not be cost effective. The best NOx control option is the burner control. Staff evaluated similar sized units from the Rule 1147 universe to assess technical feasibility of 20 ppmv. Vapor incinerators at refineries operate similarly to units at other facilities that are primarily used for VOC control although the constituents being burned could be different. Available source test results demonstrated LNB for vapor incinerators could achieve 20 ppmv.

There is only one open flare in the PR1109.1 universe. Open flares cannot be retrofitted with LNB. PR 1109.1 will include a low emission exemption for flares of less than or equal to 550 pounds of NOx per year. In addition, when the burners are being replaced, the cleanest technology will be required.

Initial BARCT Assessment and Considerations

Based on the current NOx emissions in the flue gas from thermal oxidizers and flare, and the small emissions and small units in this category, staff initially determined that 20 ppmv NOx limit for thermal oxidizers with burner replacement and flares with flare replacement is technically feasible and the limit should be determined based on the cost effectiveness analysis. There is a total of 15 units in this category, and they are primarily used for air pollution control to destruct volatile organic compounds and other waste gas streams. The units are relatively small with most units <10 MMBtu/hr and emissions tend to be low at 0.078 tons per day NOx for all units. Several stakeholders expressed concerns about the technical feasibility of achieving 20 ppmv including the concern that the waste stream and units fired on process gas could contribute to the NOx emissions and that some advanced retrofit burner technology options may require redesign/re-engineering of the entire system because unit replacement may be required to achieve 20 ppmv. Staff reached out to several burner manufacturers to reassess the technical feasibility of the 20 ppmv NOx limit. These technology vendors indicated they would guarantee 30 ppmv NOx for burner replacements although some units could be tuned to achieve <20 ppmv but it is dependent on the unit, application, and fuel, so not all units will be able to achieve 20 ppmv. Due to the concern with technical feasibility of 20 ppmv for this category, staff reassessed the cost effectiveness to achieve 30 ppmv NOx from burner upgrades.

Similar to other equipment projects, stakeholders provided revised cost data that included some costs higher than originally analyzed and could be identified as outliers. Overall, cost-effectiveness of vapor incinerators is below the established $50k threshold but several units have very high cost-effectiveness including four units with cost-effectiveness of ~$100,000 - $500,000 per ton NOx reduced. These units are currently preforming between 38 – 40 ppmv and the high cost-effectiveness is likely due to higher costs but low emission reductions. As such, the total potential emission reduction for those units is 0.0025 tons per day. Thus, staff is proposing a conditional limit of 40 ppmv.

Costs and Cost-Effectiveness Analysis

Vapor Incinerators

Staff received some revised costs from equipment in this category and for those units without cost provided, staff relied on a cost curve for burner replacement developed for Proposed Amended Rule 1147 – Miscellaneous NOx Sources and increased the estimated cost by 20% to account for Senate Bill 54. The burner replacement costs ranged from $300,000 to $7.2 million and it was determined to be cost effective at $35,000 per ton of NOx emissions reduced for burner replacement in order to meet the 30 ppmv NOx limit. Potential emission reduction is 0.048 tons per day NOx. For the conditional limit of 40 ppmv, those units are already meeting the proposed limit so no additional cost would be imposed, thus zero dollars per ton cost effectiveness. An incremental cost-effectiveness was not conducted because no other control technology was identified.

Flares

Staff relied on costs developed for the oil and gas industry for Rule 1118.1 – Emission Reductions for Non-Refinery Flares and increased the estimated cost by 20% to account for Senate Bill 54. New Low-NOx flares costs about $625,000 and annual Operation and Maintenance costs assumed to be $36,000. As shown in table below, it is not cost effective to achieve 20 ppmv with flare replacement until the unit is being replaced or exceeds the exemption limit at which time the new unit would be expected to meet 20 ppmv using the cleanest burner technology. An incremental cost-effectiveness was not conducted for units without existing controls because no other control technology was identified.

Table G-4. Cost-Effectiveness

Cost Effectiveness to 20 ppmv	
Vapor Incinerators	$35,000
Flares	~$500,000

Proposed BARCT Limits

After consulting with the NOx control technology manufacturers, reviewing facility data, and performing BARCT assessment, staff recommends setting a new NOx limit of 30 ppmv NOx for vapor incinerators with burner replacement using LNB technology with low-emitting exemption of 100 pounds NOx/year. Staff also recommends low use exemption of 550 lbs per year.

Table G-5. Proposed BARCT Limits

	NOx limit (ppmv at 3%)	Averaging Time (Rolling)	Control Technologies	Cost Effectiveness ($/ton removed)
Vapor Incinerators	30	3 hours	LNB	$35,000
Flares	20	3 hours	Low-NOx Flare	N/A[1]

(1) Existing flare will fall under low-use exemption, replacement will be required if usage exceeds the 20-hour exemption.

APPENDIX H FACILITY EMISSIONS BY UNIT

Table H-1. Chevron Remaining Emissions Based on PR 1109.1 Table 1 and Table 2

CHEVRON									
Device ID	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D641	Heater	365	68.3	24.0	5.0	14.2	N/A	N/A	Not Eligible, Red > 20 TPY
D643	Heater	220	26.2	20.3	5.0	6.5	22.0	28.4	Table D-1 Eligible
D451	Heater	102	37.0	69.8	5.0	2.6	N/A	N/A	Not Eligible, Red > 10 TPY
D3053	Gas Turbine	506	49.0	6.4	2.0	15.3	2.5	19.1	Possibly Eligible
D203	FCCU	-	49.7	6.0	2.0	16.6	8.0	66.2	Eligible
D3973	FCC SU Heater	165	-	-	5	N/A	N/A	N/A	Exempt (o)(5)
D2198	Gas Turbine	560	41.5	8.3	2.0	10.0	2.5	12.5	Possibly Eligible
D20	Heater	217	27.9	31.3	5.0	4.5	N/A	N/A	Not Eligible, Red > 20 TPY
D625	Heater	63	24.9	58.6	5.0	2.1	N/A	N/A	Not Eligible, Red > 10 TPY
D617	Heater	57	23.8	105.0	5.0	1.1	N/A	N/A	Not Eligible, Red > 10 TPY
D623	Heater	63	23.8	53.8	5.0	2.2	N/A	N/A	Not Eligible, Red > 10 TPY
D2207	Gas Turbine	560	40.2	4.4	2.0	18.3	2.5	22.9	Possibly Eligible
D502	Heater	70	21.5	85.0	5.0	1.3	N/A	N/A	Not Eligible, Red > 10 TPY
D619	Heater	57	19.2	74.3	5.0	1.3	N/A	N/A	Not Eligible, Red > 10 TPY
D504	Heater	77	18.1	83.9	5.0	1.1	N/A	N/A	Not Eligible, Red > 10 TPY
D618	Heater	57	17.5	82.8	5.0	1.1	N/A	N/A	Not Eligible, Red > 10 TPY
D620	Heater	57	17.1	74.3	5.0	1.2	N/A	N/A	Not Eligible, Red > 10 TPY

CHEVRON

Device ID	Category	Size (MMBtu/hr)	Baseline Emissions (tons)	Rep. NOx (ppmv)	Table 1 NOx Limit	Table 1 Remaining Emissions (tons)	Table 2 NOx Limit	Table 2 Remaining Emissions (tons)	Conditional Limit Eligibility
D2216	Boiler	342	15.5	47.4	5.0	1.6	7.5	2.5	Possibly Eligible
D82	Heater	315	6.3	7.9	5.0	4.0	22.0	17.6	Table D-1 Eligible
D83	Heater	315	6.9	7.9	5.0	4.4	22.0	19.3	Table D-1 Eligible
D84	Heater	219	5.4	7.9	5.0	3.4	22.0	15.1	Table D-1 Eligible
D159	Heater	176	14.9	10.4	5.0	7.1	N/A	N/A	Not Eligible, Red > 20 TPY
D160	Heater	176	16.5	10.4	5.0	8.0	N/A	N/A	Not Eligible, Red > 20 TPY
D161	Heater	176	17.1	10.4	5.0	8.2	N/A	N/A	Not Eligible, Red > 20 TPY
D955	SRU/TGI	58	22.4	58.3	30.0	11.5	N/A	N/A	No Table 2 Limit
D927	SRU/TGI	30	15.7	53.0	30.0	8.9	N/A	N/A	No Table 2 Limit
D466	Heater	~~33~~62	3.4	7.8	9.0	3.9	N/A	N/A	~~No~~ Eligible for Table 2 Limit
D467	Heater	~~33~~62	3.6	7.8	9.0	4.2	N/A	N/A	~~No~~ Eligible for Table 2 Limit
D911	SRU/TGI	30	15.4	43.4	30.0	10.7	N/A	N/A	No Table 2 Limit
D390	Heater	31	6.0	28.3	9.0	1.9	N/A	N/A	No Table 2 Limit
D453	Heater	44	3.5	21.3	5.0	0.8	18.0	3.0	Possibly Eligible
C3493	Vapor Incinerator	3	3.7	45.1	30.0	2.5	40.0	3.3	Possibly Eligible
D1910	Heater	37	3.8	38.0	9.0	0.9	N/A	N/A	No Table 2 Limit
D398	Heater	19	3.7	38.0	9.0	0.9	N/A	N/A	No Table 2 Limit
C2158	Vapor Incinerator	3	3.1	86.3	30.0	1.1	40.0	1.4	Possibly Eligible
D428	Heater	36	4.4	41.7	9.0	0.9	N/A	N/A	No Table 2 Limit
D364	Heater	26	2.0	18.1	9.0	1.0	N/A	N/A	No Table 2 Limit
C3148	Vapor Incinerator	1	0.018	80.1	30	N/A	N/A	N/A	Exempt (o)(9)
C3805	Vapor Incinerator	2	0	-	30	N/A	N/A	N/A	Exempt (o)(9)
C3806	Vapor Incinerator	2	0.032	28.3	30.0	N/A	N/A	N/A	Exempt (o)(9)

CHEVRON									
Device ID	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D3778	Heater	78	0.6	1.3	5.0	2.5	N/A	N/A	Not Eligible, Meets Table 1 Limit
D3695	Heater	83	0.8	1.9	5.0	2.1	N/A	N/A	Not Eligible, Meets Table 1 Limit
D473	Heater	88	0.4	1.7	5.0	1.3	N/A	N/A	Not Eligible, Meets Table 1 Limit
D472	Heater	123	0.7	1.7	5.0	2.0	N/A	N/A	Not Eligible, Meets Table 1 Limit
D471	Heater	177	0.8	1.7	5.0	2.3	N/A	N/A	Not Eligible, Meets Table 1 Limit
D3031	Heater	199	1.0	1.7	5.0	3.1	N/A	N/A	Not Eligible, Meets Table 1 Limit
D3530	SMR Heater	653	9.1	1.5	5.0	30.5	N/A	N/A	Not Eligible, Meets Table 1 Limit
D4354	Gas Turbine	509	9.1	1.1	2.0	16.6	N/A	N/A	Not Eligible, Meets Table 1 Limit
C4344	SRU/TGI	50	2.9	4.2	30.0	20.6	N/A	N/A	Not Eligible, Meets Table 1 Limit

Table H-2. Phillips 66 Remaining Emissions Based on PR 1109.1 Table 1 and Table 2

PHILLIPS 66										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D688	Wilm	Boiler	250	56	79	5.0	4	N/A	N/A	Not Eligible, Red > 20 TPY
D154	Wilm	Heater	110	16	64	5.0	1.3	N/A	N/A	Not Eligible, Red > 10 TPY
D155	Wilm	Heater	100	14.5	64	5.0	1.1	N/A	N/A	Not Eligible, Red > 10 TPY
D156	Wilm	Heater	70	10	64	5.0	0.8	N/A	N/A	Not Eligible, Red > 10 TPY
D157	Wilm	Heater	42	6	64	5.0	0.5	N/A	N/A	Not Eligible, Red > 10 TPY
D158	Wilm	Heater	24	3.5	64	5.0	0.3	N/A	N/A	Not Eligible, Red > 10 TPY
D1	Wilm	FCCU	-	57	14	2.0	8	N/A	N/A	Not Eligible
D44	Wilm	FCC SU Heater	87	-	-	5	N/A	N/A	N/A	Exempt (o)(5)
D687	Wilm	Boiler	179	41	61	5.0	3	N/A	N/A	Not Eligible, Red > 20 TPY
D135	Wilm	Heater	116	13.6	38	5.0	1.8	N/A	N/A	Not Eligible, Red > 20 TPY
D136	Wilm	Heater	68	8.2	38	5.0	1.1	N/A	N/A	Not Eligible, Red > 20 TPY
D137	Wilm	Heater	71	8.6	38	5.0	1.1	N/A	N/A	Not Eligible, Red > 20 TPY
D138	Wilm	Heater	56	6.6	38	5.0	0.9	N/A	N/A	Not Eligible, Red > 20 TPY
D139	Wilm	Heater	19	2	38	5.0	0.3	N/A	N/A	Not Eligible, Red > 20 TPY
D684	Wilm	Boiler	304	29	101	5.0	1	N/A	N/A	Not Eligible, Red > 20 TPY

PHILLIPS 66										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D828	Wilm	Gas Turbine	646	46	4.5	3.0	30.5	N/A	N/A	No Table 2 Limit
D264	Wilm	Heater	135	25	56	5.0	2	N/A	N/A	Not Eligible, Red > 20 TPY
D194	Wilm	Heater	60	20	82	5.0	1	N/A	N/A	Not Eligible, Red > 10 TPY
D146	Wilm	Heater	76	11	30	5.0	2	18.0	6	Possibly Eligible
D686	Wilm	Boiler	304	9	10	5.0	5	7.5	7	Possibly Eligible
D220	Wilm	SMR Heater	350	9	8	5.0	6	7.5	8	Possibly Eligible
D333	Wilm	Sulfuric Acid Furnace	74	9	14	30.0	19	N/A	N/A	Not Eligible, Meets Table 1 Limit
D332	Wilm	Sulfuric Acid SU Heater	15	0	190	9	N/A	N/A	N/A	Exempt per (o)(6)
D262	Wilm	Heater	37	5	37	9.0	1	N/A	N/A	No Table 2 Limit
D148	Wilm	Heater	27	4.3	37	9.0	1	N/A	N/A	No Table 2 Limit
D259	Wilm	Heater	39	4.4	37	9.0	1.1	N/A	N/A	No Table 2 Limit
D152	Wilm	Heater	30	4	37	9.0	1	N/A	N/A	No Table 2 Limit
D150	Wilm	Heater	38	3.6	37	9.0	0.9	N/A	N/A	No Table 2 Limit
D133	Wilm	Heater	35	3.2	37	9.0	0.8	N/A	N/A	No Table 2 Limit
D161	Wilm	Heater	31	3.5	37	9.0	0.8	N/A	N/A	No Table 2 Limit
D39	Wilm	Heater	29	2.5	37	9.0	0.6	N/A	N/A	No Table 2 Limit
D329	Wilm	Heater	29	2.5	37	9.0	0.6	N/A	N/A	No Table 2 Limit
D142	Wilm	Heater	17	2.2	37	9.0	0.5	N/A	N/A	No Table 2 Limit
D129	Wilm	Heater	27	1.8	37	9.0	0.4	N/A	N/A	No Table 2 Limit
D163	Wilm	Heater	14	1.4	37	9.0	0.3	N/A	N/A	No Table 2 Limit
D260	Wilm	Heater	17	1.4	37	9.0	0.3	N/A	N/A	No Table 2 Limit
D40	Wilm	Heater	10	1	37	9.0	0	N/A	N/A	No Table 2 Limit
D1720	Wilm	Heater	41	0	3	5.0	1	N/A	N/A	Not Eligible, Meets Table 1 Limit

PHILLIPS 66										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D1349	Wilm	SMR Heater	460	9	4	5.0	11	N/A	N/A	Not Eligible, Meets Table 1 Limit
C436	Wilm	SRU/TGI	20	2	19	30.0	4	N/A	N/A	No Table 2 Limit
C456	Wilm	SRU/TGI	20	3	15	30.0	6	N/A	N/A	No Table 2 Limit
D430	Carson	Boiler	352	96	77	5.0	6	N/A	N/A	Not Eligible, Red > 20 TPY
D210	Carson	SMR Heater	340	90.4	64	5.0	7.1	N/A	N/A	Not Eligible
D59	Carson	Heater	350	73	40	5.0	9	N/A	N/A	Not Eligible, Red > 20 TPY
D174	Carson	Heater	70	18.5	75	5.0	1.2	18.0	0.4	Possibly Eligible
D105	Carson	Heater	175	21	30	5.0	3	22.0	15	Possibly Eligible
D104	Carson	Heater	175	19	30	5.0	3	22.0	14	Possibly Eligible
D79	Carson	Heater	154	18	25	5.0	4	22.0	16	Possibly Eligible
D78	Carson	Heater	154	17	23	5.0	4	22.0	17	Possibly Eligible
D429	Carson	Boiler	352	14	10	5.0	7	7.5	10	Possibly Eligible
D713	Carson	Heater	22	1.6	30	9.0	0.5	N/A	N/A	No Table 2 Limit
C292	Carson	SRU/TGI	15	1	11	30.0	3	N/A	N/A	Not Eligible, Meets Table 1 Limit
C294	Carson	SRU/TGI	28	17	26	30.0	19	N/A	N/A	Not Eligible, Meets Table 1 Limit

- Carson Facility ID: 171109
- Wilmington Facility ID: 171107

Table H-3. Marathon Remaining Emissions Based on PR 1109.1 Table 1 and Table 2

MARATHON (TESORO REFINERY)										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D27	Carson	Heater	550	56.5	21	5	13.3	22	58.6	Not Eligible, Red > 20 TPY
D20	~~Carson~~Calciner	Coke Calciner	120	260.9	65	5	20.1	N/A	N/A	No Table 2 Limit
D570	Carson	SMR Heater	650	48.9	11	5	22.9	7.5	34.3	Table D-2 Eligibility
D629	Carson	Heater	173	27.5	32	5	4.3	22	19.1	Not Eligible, Red > 20 TPY
D535	Carson	Heater	310	27.9	23	5	6	22	26.2	Not Eligible, Red > 20 TPY
D532	Carson	Heater	255	20.8	16	5	6.3	22	27.7	Table D-1 and D-2 Eligible
D31	Carson	Heater	130	18.3	30	5	3	22	13.3	Not Eligible >25 ppmv
D151	Carson	Heater	130	18.1	36	5	2.5	22	11.2	Not Eligible >25 ppmv
D155	Carson	Heater	130	17.5	34	5	2.6	22	11.3	Not Eligible >25 ppmv
D423	Carson	Heater	80	16.5	73	5	1.1	18	4.1	Not Eligible, Red > 10 TPY
D153	Carson	Heater	130	16.9	33	5	2.6	22	11.3	Not Eligible >25 ppmv
D67	Carson	Heater	120	15.4	31	5	2.5	22	11.1	Not Eligible >25 ppmv
D29	Carson	Heater	150	14.8	28	5	2.6	22	11.6	Not Eligible >25 ppmv
D33	Carson	Heater	100	11.4	24	5	2.4	18	8.7	Table D-2 Eligibility
D539	Carson	Heater	52	5.4	23	5	1.2	18	4.2	Table D-2 Eligibility
D421	Carson	Heater	82	4.6	18	5	1.3	18	4.8	Table D-1 and D-2 Eligible
D625	Carson	Heater	39	5.4	23	9	N/A	N/A	N/A	N/A
C54	~~Carson~~ SRP	SRU/TGI	52	5.9	68	30	2.6	N/A	N/A	No Table 2 Limit

MARATHON (TESORO REFINERY)										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D250	Carson	Heater	89	3	22	5	0.7	18	2.5	Table D-2 Eligible
C910	Carson	SRU/TGI	45	25.1	34	30	22.4	N/A	N/A	No Table 2 Limit
C2413	Carson	SRU/TGI	40	14.1	19	30	22.5	N/A	N/A	No Table 2 Limit
D538	Carson	Heater	39	4.2	20	9	N/A	N/A	N/A	N/A
D416	Carson	Heater	24	3.4	28	9	N/A	N/A	N/A	N/A
D626	Carson	Heater	39	3.3	28	9	N/A	N/A	N/A	N/A
D628	Carson	Heater	39	3.4	23	9	N/A	N/A	N/A	N/A
D63	Carson	Heater	360	5.3	5.1	5	5.2	22	23	Table D-1 and D-2 Eligible
D541	Carson	Heater	39	4.3	16	9	N/A	N/A	N/A	N/A
D1465	Carson	SMR Heater	427	11	5.1	5	10.8	7.5	16.1	Table D-1 and D-2 Eligible
D627	Carson	Heater	39	3.7	17	9	N/A	N/A	N/A	N/A
C56	~~Carson~~ SRP	SRU/TGI	45	2.4	98	30	0.7	N/A	N/A	No Table 2 Limit
D419	Carson	Heater	52	1.9	15	5	0.6	18	2.3	Table D-1 and D-2 Eligible
D425	Carson	Heater	22	2.4	28	9	N/A	N/A	N/A	N/A
D1433	Carson	Heater	13	1.4	31	9	N/A	N/A	N/A	N/A
D418	Carson	Heater	11	1.3	34	9	N/A	N/A	N/A	N/A
D417	Carson	Heater	10	1.3	17	9	N/A	N/A	N/A	N/A
D1233	Carson	Gas Turbine	1,326	54.8	3	3	54.8	N/A	N/A	No Table 2 Limit
D1239	Carson	Gas Turbine	1,326	53.4	2.7	3	59.3	N/A	N/A	No Table 2 Limit
D1226	Carson	Gas Turbine	1,326	49.7	2.6	3	57.3	N/A	N/A	No Table 2 Limit
D1236	Carson	Gas Turbine	1,326	55.9	2.7	3	62.1	N/A	N/A	No Table 2 Limit
D164	Carson	FCCU	-	7.3	1	2	12.2	8	48.7	Not Eligible, Meets Table 1 Limit
D2837	Carson	FCC SU Heater	165	-	-	5	N/A	N/A	N/A	Exempt (o)(5)
C2979	Carson	Vapor Incinerator	4	2.6	35	30	2	40	2.6	Table D-1 and D-2 Eligible

MARATHON (TESORO REFINERY)										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D724/ D725	Wilm	Boiler	368	132.9	114	5	5.8	7.5	8.8	Not Eligible, Red > 20 TPY
D722/ D723	Wilm	Boiler	368	108.8	83	5	6.5	7.5	9.8	Not Eligible, Red > 20 TPY
D76/ D77	SRP	Boiler	225	34.7	48	5	3.6	7.5	5.5	Not Eligible, Red > 20 TPY
D812	Wilm	Gas Turbine	392	65.4	8	3	25.2	N/A	N/A	No Table 2 Limit
D810	Wilm	Gas Turbine	392	59.6	10	3	18.1	N/A	N/A	No Table 2 Limit
D32	Wilm	Heater	218	43.1	59	5	3.7	22	16.2	Not Eligible, Red > 20 TPY
D9	Wilm	Heater	200	37.5	40	5	4.7	22	20.5	Not Eligible, Red > 20 TPY
D247	Wilm	Heater	82	8	43	5	0.9	18	3.3	Not Eligible >25 ppmv
D248	Wilm	Heater	50	9.4	43	5	1,1	18	3.9	Not Eligible >25 ppmv
D249	Wilm	Heater	29	4.2	43	5	0.5	18	1.7	Not Eligible >25 ppmv
D146	Wilm	Heater	69	23.3	134	5	0.9	18	3.1	Not Eligible, Red > 10 TPY
D33	Wilm	Heater	252	22.6	17	5	6.5	22	28.6	Eligible < Table 2
D388	Wilm	Heater	147	15.2	16	5	4.7	22	20.8	Table D-1 and D-2 Eligible
D214	Wilm	Heater	56	2.9	17	5	0.8	18	3.1	Eligible < Table 2
D215	Wilm	Heater	36	2.6	17	5	0.8	18	2.8	Eligible < Table 2
D216	Wilm	Heater	31	2	17	5	0.6	18	2.2	Eligible < Table 2
D217	Wilm	Heater	31	4.6	17	5	1.4	18	4.9	Eligible < Table 2

MARATHON (TESORO REFINERY)										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D158	Wilm	Heater	204	9.4	84	5	0.6	22	2.5	Not Eligible >25 ppmv
D386	Wilm	Heater	48	2.2	19	5	0.6	18	2.1	Eligible <25 ppmv
D387	Wilm	Heater	71	3.9	19	5	1	18	3.6	Table D-2 Eligible
D120	Wilm	Heater	45	8.9	63	5	0.7	18	2.6	Not Eligible >25 ppmv
D157	Wilm	Heater	49	8.7	63	5	0.7	18	2.5	Not Eligible >25 ppmv
D218	Wilm	Heater	60	7.2	26	5	1.4	18	5.1	Not Eligible >25 ppmv
D384	Wilm	Heater	48	2.2	18	5	0.6	18	2.2	Table D-1 and D-2 Eligible
D385	Wilm	Heater	24	1.1	18	5	0.3	18	1.1	Table D-1 and D-2 Eligible
D1122	Wilm	Boiler	140	1.9	7	5	1.3	7.5	2	Table D-1 and D-2 Eligible
D777	Wilm	SMR Heater	146	5.4	7	5	3.7	7.5	5.6	Table D-1 and D-2 Eligible
D250	Wilm	Heater	35	2.3	31	9	N/A	N/A	N/A	N/A
D770	Wilm	Heater	63	1.6	7	5	1.1	18	4	Table D-1 and D-2 Eligible

- Carson Facility ID: 174655
- Wilmington Facility ID: 800436
- Coke Calciner Facility ID: 174591
- Sulfur Recovery Plant (SRP) Facility ID: 151798

Table H-4. Torrance Refinery Remaining Emissions Based on PR 1109.1 Table 1 and Table 2

TORRANCE REFINERY									
Device ID	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D803	Boiler	309	203.5	116.8	5.0	8.7	N/A	N/A	Not Eligible, Red > 20 TPY
D805	Boiler	291	141.8	35.2	5.0	20.1	N/A	N/A	Not Eligible, Red > 20 TPY
D151	FCCU	-	100.7	10.3	2.0	19.6	8.0	78.2	Eligible
C164	CO Boiler	464	-	-	2.0	-	8.0	-	Eligible
D2320	FCC SU Heater	132	-	-	5	N/A	N/A	N/A	Exempt (o)(5)
D913	Heater	457	48.5	16.3	5.0	14.9	N/A	N/A	Not Eligible, Red > 20 TPY
D914	Heater	161	16.3	16.3	5.0	5.0	N/A	N/A	Not Eligible, Red > 20 TPY
D917	Heater	91	23.9	60.6	5.0	2.0	N/A	N/A	Not Eligible, Red > 10 TPY
D918	Heater	91	24.5	67.6	5.0	1.8	N/A	N/A	Not Eligible, Red > 10 TPY
D120	Heater	126	21.0	70.0	5.0	1.5	~~N/A~~22	~~N/A~~6.6	Possibly Eligible
D930	Heater	129	23.6	51.2	5.0	2.3	N/A	N/A	Not Eligible, Red > 20 TPY
D83	Heater	67	16.7	52.5	5.0	1.6	N/A	N/A	Not Eligible, Red > 10 TPY
D84	Heater	67	16.2	53.0	5.0	1.5	N/A	N/A	Not Eligible, Red > 10 TPY
D85	Heater	74	15.4	43.2	5.0	1.8	N/A	N/A	Not Eligible, Red > 10 TPY
D931	Heater	73	13.8	51.2	5.0	1.3	N/A	N/A	Not Eligible, Red > 10 TPY
D269	Heater	107	10.6	43.1	5.0	1.2	18.0	4.4	Possibly Eligible

TORRANCE REFINERY									
Device ID	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D920	Heater	108	7.1	22.4	5.0	1.6	18.0	5.7	Table D-2 Eligible
D1239	Boiler	340	8.0	7.2	5.0	5.6	7.5	8.4	Table D-1 and D-2 Eligible
D1236	Boiler	340	4.9	5.8	5.0	4.3	7.5	6.4	Table D-1 and D-2 Eligible
C626	Vapor Incinerator	60	7.2	45.4	30.0	4.8	40.0	6.4	Possibly Eligible
D949	Heater	40	3.5	23.8	9.0	1.3	N/A	N/A	No Table 2 Limit
D234	Heater	60	0.5	13.1	5.0	0.2	18.0	0.7	Table D-1 and D-2 Eligible
D235	Heater	60	1.0	13.1	5.0	0.4	18.0	1.4	Table D-1 and D-2 Eligible
D950	Heater	64	1.4	11.7	5.0	0.6	18.0	2.2	Table D-1 and D-2 Eligible
C686	Vapor Incinerator	4	2.8	38.0	30.0	2.2	40.0	3.0	Possibly Eligible
D927	Heater	17	3.0	11.7	9.0	2.3	N/A	N/A	No Table 2 Limit
D231	Heater	60	0.4	13.1	5.0	0.2	18.0	0.6	Table D1 and D-2 Eligible
D232	Heater	60	0.5	13.1	5.0	0.2	18.0	0.6	Table D-1 and D-2 Eligible
D928	Heater	17	2.6	11.7	9.0	2.0	N/A	N/A	No Table 2 Limit
D929	Heater	21	0.4	27.1	9.0	0.1	N/A	N/A	No Table 2 Limit
D1403	Heater	21	0.4	27.1	9.0	0.1	N/A	N/A	No Table 2 Limit
C687	Vapor Incinerator	4	1.2	38.0	30.0	0.9	40.0	1.3	Possibly Eligible
C952	SRU/TGI	100	15.9	19.6	30.0	24.3		N/A	Not Eligible, Meets Table 1 Limit

Table H-5. Ultramar Remaining Emissions Based on PR 1109.1 Table 1 and Table 2

ULTRAMAR (VALERO)										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D36	Wilm	FCCU	-	87.7	23.3	2	7.5	8	30.1	Not Eligible
D38	Wilm	FCC SU Heater	100	-	-	5	N/A	N/A	N/A	Exempt (o)(5)
D74	Wilm	Heater	258	30.9	38.4	5	4	22	-	Not Eligible, Red > 20 TPY
D3	Wilm	Heater	159	17.2	30.8	5	2.8	22	12.3	Possibly Eligible
D6	WIlm	Heater	136	13.5	19	5	3.6	22	15.6	Table D-1 and D-2 Eligible
D52	Wilm	Heater	36	18.9	96	9	1.8	N/A	N/A	No Table 2 Limit
D22	Wilm	Heater	95	9.5	29.8	5	1.6	18	5.7	Possibly Eligible
D12	Wilm	Heater	144	8.8	26.7	5	1.7	22	7.3	Possibly Eligible
D53	Wilm	Heater	68	8.2	23.2	5	1.8	18	6.4	Table D-2 Eligible
D8	Wilm	Heater	49	6.3	34.4	5	0.9	18	3.3	Possibly Eligible
D98	Wilm	Heater	57	5.8	23.1	5	1.2	18	4.5	Table D-2 Eligible
D768	Wilm	Heater	110	5.9	10.3	5	2.9	18	10.3	Table D-1 and D-2 Eligible
D1550	Wilm	Boiler	245	5.4	5.2	5	5.2	7.5	7.7	Table D-1 and D-2 Eligible
D73	Wilm	Heater	30	4.8	20.7	9	2.1	N/A	N/A	No Table 2 Limit
D59	Wilm	Heater	26	3.2	33.5	9	0.9	N/A	N/A	No Table 2 Limit
D60	Wilm	Heater	30	3.6	26.2	9	1.2	N/A	N/A	No Table 2 Limit
D429	Wilm	Heater	30	1	6.3	5	0.8	22	3.5	Table D-1 and D-2 Eligible
D430	Wilm	Heater	200	6.5	6.3	5	5.2	22	22.7	Table D-1 and D-2 Eligible
D9	Wilm	Heater	20	2.5	25.7	9	0.9	N/A	N/A	No Table 2 Limit

ULTRAMAR (VALERO)										
Device ID	**Facility**	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Rep. NOx (ppmv)**	**Table 1 NOx Limit**	**Table 1 Remaining Emissions (tons)**	**Table 2 NOx Limit**	**Table 2 Remaining Emissions (tons)**	**Conditional Limit Eligibility**
D378	Wilm	Boiler	128	2.6	5.6	5	2.3	7.5	10.2	Table D-1 and D-2 Eligible
C1260	Wilm	SRU/TGI	36	3	89.8	30	1	N/A	N/A	No Table 2 Limit
D377	Wilm	Boiler	39	0	0	5	0	7.5		Not Eligible, Meets Table 1 Limit
D1669	Wilm	Gas Turbine	342	3.2	2.1	2	3.1	2.5	3.8	~~Possibly~~ Eligible
D179	Asphalt Plant	Heater	15.4	0.03	13.5	9	0.01	N/A	N/A	N/A
D13	Asphalt Plant	Heater	19.3	2.9	20.7	9	1.6	N/A	N/A	N/A
D63	Asphalt Plant	Boiler	14.5	1.9	31	5	1.6	N/A	N/A	N/A
D64	Asphalt Plant	Boiler	14.5	~~0~~1.9	~~0~~30.1	5	~~0~~1.6	N/A	N/A	N/A

- Wilmington Facility ID: 800026
- Valero Asphalt Plant Facility ID: 800393

Table H-6. Air Products Emissions Based on PR 1109.1 Table 1 and Table 2

AIR PRODUCTS								
Device ID	Facility	Category	Size (MMBtu/hr)	Baseline Emissions (tons)	Representative NOx (ppmv)	Table 1 NOx Limit	Table 2 NOx Limit	Conditional Limit Eligibility
D30	Carson	SMR Heater	764	16.5	3.9	5	7.5	Not Eligible, Meets Table 1 Limit
D38	Wilmington	SMR Heater	785	21.6	5.7	5	7.5	Eligible for Table 2 Limit
D367	Torrance	SMR Heater	527	131.1	53.4	5	7.5	Not Eligible for Table 2 Limit
D925/ D926*	Torrance	SMR Heater/GTG	1,247	29.9	4.4	5	N/A	N/A

*Device ID D925 and D926 share a combined stack, however D926 is owned by Torrance Refinery. Air Products is responsible for the combined stack and emissions for both D925 and D926.

Table H-7. Air Liquide Emissions Based on PR 1109.1 Table 1 and Table 2

AIR LIQUIDE								
Device ID	Facility	Category	Size (MMBtu/hr)	Baseline Emissions (tons)	Representative NOx (ppmv)	Table 1 NOx Limit	Table 2 NOx Limit	Conditional Limit Eligibility
D24	El Segundo	SMR Heater	780	20	3.7	5	7.5	Not Eligible, Meets Table 1 Limit

Table H-8. Lunday-Thagard Emissions Based on PR 1109.1 Table 1 and Table 2

LUNDAY THAGARD (WORLD OIL)							
Device ID	Category	Size (MMBtu/hr)	Baseline Emissions (tons)	Representative NOx (ppmv)	Table 1 NOx Limit	Table 2 NOx Limit	Conditional Limit Eligibility
D19	Heater	6	0.87	12	9	N/A	N/A
D20	Heater	39.0	12.2	49	9	N/A	N/A
D84	Heater	5.5	0.74	58	9	N/A	N/A
D214	Boiler	29.4	0.10	7.9	5	N/A	N/A
D231	Boiler	39.9	0.78	7.4	5	N/A	N/A
C97	Vapor Incinerator	14	11.2	88	30	40	Not Eligible
C105	Vapor Incinerator	1.4	0.56	101	30	40	Not Eligible

Table H-9. Eco-Services Emissions Based on PR 1109.1 Table 1 and Table 2

ECO-SERVICES							
Device ID	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Representative NOx (ppmv)**	**Table 1 NOx Limit**	**Table 2 NOx Limit**	**Conditional Limit Eligibility**
D1	Sulfuric Acid Furnace	150	~~16.5~~23.3	22	30	N/A	N/A
D98	SU Heater	50	~~21.6~~0.38	~~49~~94.4	5	N/A	Exempt (o)(6)
D139	SU Boiler	49	~~0.74~~0.19	29.6	5	N/A	Exempt (o)(6)
C126	Flare	1.09	~~0.1~~0.22	-	20	N/A	Exempt (o)(8)

Table H-10. AltAir Emissions Based on PR 1109.1 Table 1 and Table 2

ALTAIR							
Device ID	**Category**	**Size (MMBtu/hr)**	**Baseline Emissions (tons)**	**Representative NOx (ppmv)**	**Table 1 NOx Limit**	**Table 2 NOx Limit**	**Conditional Limit Eligibility**
D44	Heater	12.8	-	2.7	9	N/A	Meets Table 1 Limit
D45	Heater	5	-	2.7	9	N/A	Meets Table 1 Limit
D46	Heater	28	0.32	2.7	9	N/A	Meets Table 1 Limit
D374	Boiler	44.5	6.2	71.6	5	7.5	Not Eligible
D375	Boiler	44.5	0	-	5	7.5	Not Eligible
D376	Boiler	65.9	8.4	105.1	5	7.5	Not Eligible
C175	Vapor Incinerator	10	3.7	110	30	N/A	N/A
D691	Vapor Incinerator	8	0	-	30	N/A	N/A
C882	Vapor Incinerator	1.2	0.12	-	30	40	Exempt (o)(9)
C887	Vapor Incinerator	1.2	0.25	-	30	40	Exempt (o)(9)
C531	Vapor Incinerator	30	4.7	68.2	30	40	Not Eligible
D569	Vapor Incinerator	8	-	-	30	40	Not Eligible
D677/D679	Gas Turbine/Duct Burner	140	0	1.7	2	2.5	Eligible for Table 2, Unit has permit limit of 2.5 ppmv

APPENDIX I RESPONSE TO COMMENTS

Public Workshop Comments

Staff held a Public Workshop on September 1, 2021 to provide a summary of PR 1109.1, PR 429.1, PAR 1304, PAR 2005, and PRR 1109. The following is a summary of the comments received on PR 1109.1 and staff's responses.

Commenter #1: Chris Chavez– Coalition for Clean Air

The commenter expressed concern regarding the flexibility options in PR 1109.1 and the legal ramifications for violations if not meeting the goals set out in the plans.

Staff Response to Commenter #1:

PR 1109.1 is estimated to cost the petroleum refineries between $179 million to $1 billion to comply and will require approximately 75 SCR installations, 25 SCR upgrades and many burner replacements. Staff worked to craft a rule that would maximize emission reductions but allow flexibility so the costs for projects with high cost and low emission reductions could be used elsewhere. Alternate compliance plans provide flexibility for affected facilities in deciding which projects are more or less cost-effective to achieve greater emission reductions that would be achieved if each unit was operated at the BARCT NOx limit. Under B-Plan and B-Cap, each unit will be required to take a NOx concentration limit on the permit.

Violations of the rule are subject to penalties and fines under the Health and Safety Code. There are multiple dates in PR 1109.1 that must be met by the owner or operator of the facility. In addition, the emission limits and each condition in the Permit to Construct and Permit to Operator are enforceable as well as the approved I-Plan, B-Plan, and B-Cap.

Commenter #2: Julia May – Communities for a Better Environment

Commenter stated that based on the data in the staff report, it shows that 88 percent of the equipment at facilities subject to the RECLAIM is not at BARCT. This shows the RECLAIM program failed and modern controls were not installed. Refineries are getting a good deal with the flexibility in the schedule in PR 1109.1. All equipment should be required to meet the most stringent NOx levels. The expected emission reductions are lower due to the flexibilities provided and an extra 1 tpd of reductions with the most stringent standards can be achieved.

Staff Response to Commenter #2:

While a number of facilities under the RECLAIM program did not install control equipment on all of their equipment, they still complied with the requirements and program elements of RECLAIM. As a command-and-control rule, PR 1109.1 will require NOx limits on each affected unit with a majority required to install effective NOx control equipment to meet the stringent emission standards. With regards to flexibility in the schedule, PR 1109.1 establishes various implementation options for facilities to meet emission reduction targets at different deadlines. The implementation schedules account for the variability that could occur during the process (e.g., permitting time) and reflect realistic planned turnaround times to properly schedule when projects can be completed. As such, the implementation schedules recognize the time needed to design, engineer, budget, order, deliver, logistics, install, and commission, in order to properly meet a scheduled turnaround or target deadline. Staff has provided additional time and flexibility in the schedules for implementing the emission control projects, including provisions for an extension of the schedule.

The flexibilities in the B-Plan and B-Cap are required to achieve the emission reduction goals in PR 1109.1, due to the complexity of the projects and the total number of equipment to be retrofitted within different class and categories of equipment in the rule. The I-Plan provides the flexibility to align the projects with the facility's scheduled turnarounds to avoid additional cost, downtime, and potential disruptions to the fuel supply.

Commenter #3: Emily Spokes – member of the community

Commenter expressed concerns for the people who are working at the refineries as being at the front line of enduring loss.

Staff Response to Commenter #3:

Staff appreciates the comment and anticipates the outcome of the proposed project will provide an air quality and public health benefit to the regional air quality, local communities, as well as onsite workers.

Commenter #4: Oscar Espino Padron– Earthjustice

Commenter expressed concern regarding the flexibility provided to the refineries through alternative plans under PR 1109.1 and stated that there is a need for stronger guardrails to ensure refineries are complying with the established targets. The commenter stated that PR 1109.1 includes no clear language or listed penalties in this regard. The commenter requested a mechanism for the agency to reassess whether the 9ppmv compliance deadline for boilers and process heaters can be moved up if emerging technologies are available sooner than the 10-year timeframe in the PR 1109.1. The commenter also expressed concerns related to the inconsistency of start-up and shutdown provisions in the rule with the Clean Air Act.

Staff Response to Commenter #4:

Please see the Response to Comment 1-1 regarding plan flexibility and enforcement penalties if a facility fails to meet the targets or deadlines. For the emerging technology, staff intends to conduct a technology assessment to evaluate the progress of the burner technologies to achieve levels at or below 9 ppmv but does not intend to require the transition to the emerging technologies on an earlier timeframe. Staff worked to develop a compliance schedule that will work for each of the facility's future turnaround schedules and any unanticipated changes to a future implementation schedule would be challenging. While staff does not intend to shorten the ten-year effective date for the burner replacement, PR 1109.1 does include a shorter timeframe for when the facility has to track the cumulative replacement of the burners. Cumulative burner replacement is what triggers the 9 ppmv concentration limit and is tracked starting five years from rule adoption. The five-year timeframe is needed to allow units not meeting 40 ppmv to retrofit to meet the initial 40 ppmv limit. After five years, any burner replacement is considered as part of the cumulative burner replacement; therefore, any facility that replaces more than 50 percent of their burners starting after five years will have to transition to 9 ppmv as soon as 10 years from rule adoption. This provision is to prevent a facility from replacing the burners in their boilers and heaters before the 10-year effective date in order to delay installing burners to meet the 9 ppmv NOx limits.

For the startup and shutdown comment, please see staff's response in the Staff Report for PR429.1.

Commenter #5: Byron Chan – Earthjustice

Commenter asked about the timeline that staff considers for issuing the permits to construct by AQMD as the reference in determination of compliance date in I-Plan.

Staff Response to Commenter #5:

Engineering staff estimates it will take 12 to 18 months from submittal of a complete permit application to evaluate and issue a permit to construct. The proposed rule provides contingency provisions if the permit takes longer to issue which could impede in the project's ability to be included in next planned turnaround.

Commenter #6: Michael Carroll – Latham & Watkins LLP

Commenter stated that in order to meet the stringent standards and target reductions, rule compliance flexibility and extended timelines are necessary.

Staff Response to Commenter #6:

Staff supports compliance flexibility with conditional limits and implementation options in order to ensure the stringent BARCT limits will be achieved.

Comment Letters

Comment Letter #1

NANETTE DIAZ BARRAGÁN
44TH DISTRICT, CALIFORNIA
FACEBOOK.COM/CONGRESSWOMANBARRAGAN
TWITTER: @REPBARRAGAN

COMMITTEE ON ENERGY AND COMMERCE
SUBCOMMITTEES:
HEALTH
ENVIRONMENT AND CIMATE CHANGE
ENERGY

COMMITTEE ON HOMELAND SECURITY
SUBCOMMITTEES:
BORDER SECURITY, FACILITATION, AND OPERATIONS
CHAIRWOMAN

CONGRESSIONAL HISPANIC CAUCUS
FIRST VICE CHAIR

Congress of the United States
House of Representatives
Washington, DC 20515

WASHINGTON OFFICE:
2246 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, DC 20515
(202) 225-8220

DISTRICT OFFICES:

MAIN OFFICE
302 W. FIFTH STREET, SUITE 201
SAN PEDRO, CA 90731
(310) 831-1799

701 E. CARSON STREET
CARSON, CA 90745

8650 CALIFORNIA AVENUE
SOUTH GATE, CA 90280

205 S. WILLOWBROOK AVENUE
COMPTON, CA 90220

August 27, 2021

Governing Board
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Dear South Coast Air Quality Management District Governing Board:

I am writing in regard to the South Coast Air Quality Management District (SCAQMD) Governing Board's consideration to adopt Proposed Rule 1109.1. By reducing nitrogen oxide (NOx) emissions by an estimated seven to nine tons per day, this rule would have a significant impact on improving regional air quality and protecting public health. I respectfully urge the SCAQMD Governing Board to commit to the following:

Voting to adopt Proposed Rule 1109.1 by the November 2021 Governing Board meeting. At the December 2020 Governing Board meeting, the vote was proposed for June 2021. Since then, the vote has been postponed twice more and is now scheduled for November 2021. During this time, NOx emissions from refineries have continued to disproportionately affect frontline communities of color, including in Carson and Wilmington, resulting in elevated rates of asthma, cancer, and other environmental health impacts. 1-1

Include a 2 parts per million (ppm) NOx standard for all large boilers and heaters within Proposed Rule 1109.1. By applying this standard to boilers and heaters which burn more than 40 million British Thermal Units (BTUs) of gas per hour, the rule would achieve a 95% reduction in regional NOx emissions. Currently, the refineries in Carson and Wilmington, California alone emit approximately 4.5 tons of NOx emissions per day. A strong rule with a 2 ppm standard will have tremendous impact throughout the region, and particularly in the communities most harmed by environmental inequities. 1-2

No exemptions for refineries during startup, shutdown, and malfunction periods. Refineries must be held accountable to the standards of Proposed Rule 1109.1 during non-compliance periods that are a result of inadequate equipment maintenance, operator error, or other negligence. These exemptions would provide an incentive to pollute without limitations during equipment startup and shutdown. 1-3

Proposed Rule 1109.1 is the Governing Board's opportunity to correct decades of environmental harm and devastating health impacts caused by the lack of strong air quality regulations and the 1-4

Rep. Barragán
Page 2

necessary enforcement. The equipment upgrades required via best available retrofit control technology are cost effective and overdue. Implementing the rule will address some of the shortcomings of the Regional Clean Air Incentives Market (RECLAIM) Program by ensuring refineries invest in the equipment required to reduce emissions. 1-4 (con'td)

As the Representative of California's 44th Congressional District, I urge the Governing Board to thoroughly consider the public's health by voting to adopt a strong Proposed Rule 1109.1 as soon as possible. Thank you for your attention to this urgent matter.

Sincerely,

Nanette Diaz Barragán

Nanette Diaz Barragán
Member of Congress

Staff Response to Commenter Letter #1:

Response to Comment 1-1:

Staff is working to keep the rule development schedule on track for the Governing Board to consider approval of PR 1109.1, and companion rules at the November 5, 2021 Governing Board meeting.

Response to Comment 1-2:

For boilers and heaters ≥40 MMBtu/hr, staff originally proposed a BARCT limit of 2 ppmv based on the combination of new Ultra-Low NOx Burners (ULNB) and Selective Catalytic Reaction (SCR) (Working Group meeting #9 held on December 12, 2019). Industry stakeholders raised concerns regarding the ability to replace existing Low-NOx Burners (LNBs) with ULNBs since many of the units are older and not designed for ULNBs which require more spacing. The recommended American Petroleum Institute (API) guidelines were cited for refinery fired heaters (API 560) and burners (API 535) that include heat density and minimum burner spacing for optimal operation and safety. A higher heat density (MMBtu/hr/ft^2) can result in higher flame temperatures and therefore increase NOx emissions. If burner spacing is not adequate, this can lead to flame interactions or coalescing which results in increased NOx emissions and potential impingement of the tubes. While the guidelines are not requirements, not operating within guidelines is considered "suboptimal" which can impact burner NOx performance. Third party engineering consultants, Norton Engineering, concluded in their report that under conditions that are optimal, 30 ppmv NOx can be achieved with ULNB, but suboptimal burner installations will achieve 40 – 50 ppmv. For those ULNB applications achieving 50 ppmv, the 2 ppmv will not be technically feasible even with 95% reduction from SCR. The report specifically noted:

> "*For older heaters designed with prior burner technologies the above-mentioned criteria (flame length, heat flux, fuel conditioning, burner spacing, turndown) are rarely achieved when upgrading to newer ULNB. In situations where an existing heater is constrained, as mentioned earlier, upgrading to ULNB may not achieve the lowest NOx emission level demonstrated by the technology.*"

Two refineries in recent years experienced these highlighted issues when attempting to convert the existing burners to ULNB. As a result, both refineries retracted their projects over safety concerns. Because of these ULNB challenges, staff re-focused on the SCR technology, which is a proven, highly effective, reliable option in lowering the NOx emissions from larger heaters and boilers.

Regarding SCR, Norton was not confident that single bed SCR would achieve the 2 ppmv NOx level stating, "*SCR designs can achieve 92 to 94% NOx reduction in a single catalyst bed with NH3 slip in the 5 to 10 ppmv range*." The report acknowledged that "*multiple catalyst beds, often times with an additional ammonia injection grid between the beds, is required to achieved NOx reduction levels greater than ~94%. The addition of catalyst beds is the most effective means of ensuring that SCR systems can reliably achieve sub 10 ppmv NOx emission levels*."

Taking the advice provided by the consultants, staff conducted a further technology search and concluded that there are alternative pathways that do not involve installation of ULNB in those older units where space and safety could be a problem. Such alternatives could be adding another stage or layer of catalyst in the SCR reducing NOx emissions down to 2 ppmv (Working Group Meeting #17). However, in doing so, there is an increase in cost for additional equipment, ammonia, and installation due to the higher footprint of the two-stage SCR compared to the single-stage installation. Stakeholders indicated costs could increase by over 80 percent.

Facilities submitted the revised cost data, and staff reassessed proposed BARCT limits for equipment categories that were affected such as boilers and heaters ≥ 40 MMBtu/hr. If cost data was not provided, staff used facilities' suggested cost of 80% increase of single-stage reactor for two-stage SCR. Revised cost estimates for boilers ranged from \$2 MM to \$70 MM and revised cost estimates for heaters ranged from \$5 MM to \$244 MM to achieve 2 ppmv with a two-stage SCR, ULNB single stage, or unit replacement. Therefore, the proposed requirement to meet 2 ppmv with the revised cost data was determined to be not cost-effective. Using the single-stage SCR, however, could technically achieve 5 ppmv, and the revised cost estimates were much less due to less equipment, less ammonia, and less space challenges. The revised cost estimates for boilers ranged from \$10 MM to \$40 MM, and revised cost estimates for heaters ranged from \$2 MM to \$45 MM to achieve 5 ppmv with a single stage SCR.

California Health & Safety Code Section 40920.6(a)(3) requires a calculation of the incremental cost effectiveness for potential control options by determining cost differences divided by the difference in emission reduction potentials between each progressively more stringent potential control option as compared to the next less expensive control option. As such, the comparison of the 5 ppmv NOx limit to the more stringent control option at 2 ppmv was evaluated, and it was determined to be not cost effective. For boilers and heaters, the incremental cost effectiveness from 5 ppmv to 2 ppmv was determined to be, respectively, \$159,000 and \$656,000 per ton of NOx reduced. Thus, to propose the more stringent potential control option at 2 ppmv was determined to be not cost effective and not recommended as the BARCT limit for these categories. However, installing single stage SCR on an existing unit with LNBs still proves to be effective and reducing NOx emissions and cost-effective to achieve a BARCT level of 5 ppmv and is recommended by staff.

Response to Comment 1-3:

Please see staff's response in the Staff Report for PR429.1.

Response to Comment 1-4:

Transitioning facilities from the RECLAIM program to a command-and-control regulatory program will require all units under RECLAIM to meet NOx emission limits that are representative of BARCT or BARCT in the aggregate. Implementation of PR 1109.1 provides assurance that NOx reductions will occur at petroleum refineries and facilities with related operation to petroleum refineries.

Comment Letter #2a:

This email, or a version similar to this email, was received by the Clerk of the Board from over 1,000 members of the public.

> Dear c/o Clerk of Board South Coast Air Quality Management Governing Board,
>
> I urge you to adopt Refinery Rule 1109.1 to help our region meet air-quality standards and protect public health.
>
> Southern California has the worst ground-level ozone pollution in the nation. It threatens the health of residents with a range of harms, including asthma, diminished lung function and premature death. These harms cause negative socioeconomic impacts such as increased health care costs, missed workdays and school absences.
>
> Petroleum refineries are a major source of ozone pollution. State law requires life-saving pollution control technologies to be installed on large emissions sources. But refineries have avoided making these upgrades to save themselves millions of dollars — and they continue to delay. Refinery Rule 1109.1 would require them to finally install controls on equipment such as large boilers and heaters, which will create jobs as well as improve public health.
>
> Communities living near refineries can't afford to wait any longer. It's time to adopt a strong Refinery Rule 1109.1 to secure maximum emissions reductions at petroleum refineries as quickly as possible.

Staff Response to Comment Letter #2a:

Staff is working to keep the rule development schedule on track for the Governing Board to consider approval of PR 1109.1, and companion rules, at the November 5, 2021 Governing Board meeting. The purpose of PR 1109.1 is to require emission reductions on all emission sources at the petroleum refineries, including large boilers and heaters. The Socioeconomic Assessment concluded the proposed project would generate jobs and result in benefits to public health in terms of avoiding premature deaths, asthma attacks, and loss of workdays.

Comment Letter #2b:

Monday, August 30, 2021

Clerk of the Board,
South Coast AQMD,
21865 Copley Drive
Dimond Bar, CA 91765-4178

South Coast Air Quality Management District Governing Board Members:

The Sierra Club submits the following 560 digital signatures on the behalf of our members and supporters, urging the South Coast Air Quality Management District to implement a strong Refinery Rule (1109.1).

Petition Language:

Dear Governing Board Members:

We submit this letter in support of Refinery Rule 1109.1, which would bring our region closer to meeting air quality standards to protect public health.

Our region continues to have the worst ground-level ozone pollution in the nation. This pollution threatens the health of residents in the region with a range of harms, including asthma, diminished lung function, and premature death. These harms, in turn, cause negative socio-economic impacts, such as increased health care costs, missed workdays, and school absences.

Petroleum refineries are a major source of ozone-causing pollution. For decades, refineries have avoided installing available life-saving pollution controls on hundreds of pieces of equipment, such as large boilers and heaters. As a result, refineries have saved millions of dollars. Refinery Rule 1109.1 would require refineries to finally install available controls on equipment that will improve public health and create jobs.

We encourage you to adopt a strong Refinery Rule 1109.1 that secures the maximum amount of emissions reductions at petroleum refineries as quickly as possible. Refineries have had five years to install these pollution controls but have delayed making these necessary investments and are currently lobbying to keep delaying indefinitely. Communities living near refineries have waited for far too long and cannot afford to wait any longer.

Staff Response to Comment Letter #2b:

Staff appreciates the comment. PR 1109.1 is needed to reduce NOx emissions, which is an ozone precursor. Three of the five major petroleum refineries are located in the AB 617 communities of Wilmington, Carson, and Long Beach. Emission reductions will help reduce emissions in these communities and communities surrounding the other refineries. Staff is working to keep the rule development schedule on track for the Governing Board to consider approval of PR 1109.1, and companion rules, at the November 5, 2021 Governing Board meeting.

Comment Letter #3:

Valero

September 10, 2021

Ms. Susan Nakamura
Assistant Deputy Executive Officer, Planning & Rules
South Coast Air Quality Management District
Diamond Bar, CA 91765
Via electronic mail at Snakamura@aqmd.gov

Re: Proposed Rule 1109.1

Dear Ms. Nakamura,

Ultramar Inc. (Valero) submits the following comments on South Coast Air Quality Management District (SCAQMD or District) Proposed Rule 1109.1, based on the September 1 Workshop version of the rule and the accompanying preliminary draft staff report. Valero operates a petroleum refinery in Wilmington, California and would be subject to the proposed rule as adopted by the District Governing Board. Valero supports the District's efforts to reduce emissions in the South Coast Air Basin (basin) and looks forward to continuing working with the District to identify feasible, cost-effective solutions.

The purpose of the proposed rule is to establish current and future best available retrofit control technology (BARCT) for various NOx emitting equipment at the five refineries in the basin and associated industries, while transitioning these facilities from the current regulatory scheme established by NOx RECLAIM.

We appreciate the tremendous effort staff has put into this complex task and the time that staff has taken to try to understand our particular issues. Valero is the smallest refinery in the basin in both volume and footprint and has unique constraints in constructing additional controls. With the very limited available space at the refinery, we must carefully engineer any add-on controls for affected equipment, which is a time and resource-intensive exercise unique to Valero's operations. Staff has included several provisions in the proposed rule that are very helpful, such as recognizing current BARCT (Interim Limits) and the need to schedule turnarounds to install controls to implement future-effective BARCT.

However, Valero still has several issues with the current proposal, most of which relate to the proposed fluid catalytic cracking unit (FCCU) BARCT of 8 ppm for some units with existing controls and 2 ppm for others.

RECLAIM

First, we do not believe staff has properly considered the baseline for purposes of determining BARCT for FCCUs. The proposal begins with a baseline that looks at the state of equipment and controls at each facility and largely ignores the fact that facilities took efforts to comply with the RECLAIM Program since its 3-1

Wilmington Refinery • Ultramar Inc., a Valero Company
2402 E. Anaheim • Wilmington, CA 90744 • Telephone (562) 491-6877

inception in 1993 and the multiple methods taken to achieve emission targets. The approach taken does not transition from existing RECLAIM, rather it establishes a new rule as though no current BARCT regulations exist. No effort is made in the proposed rule to deconstruct RECLAIM, rather, it completely overlooks the current BARCT strategies that comprise RECLAIM. This is largely due to the misconception that RECLAIM failed because not all equipment at refineries has control equipment installed. This was never a metric of RECLAIM. The success of RECLAIM was meant to be measured by the overall programmatic reduction in mass emissions that were equivalent to those that would be achieved by command and control rules and did not specify specific controls[1]. Participation in the program through RECLAIM trading credit purchases essentially subsidized installation of controls at other facilities by providing funds to offset the cost to install control equipment. Ignoring the actions facilities took to comply with RECLAIM puts many RECLAIM facilities that relied on the program as designed and implemented at a disadvantage as compared to others, depending on how a facility opted to comply.

BARCT under RECLAIM was properly implemented through a very involved process of looking at all of the equipment under the program, determining appropriate BARCT, including future-effective BARCT for each equipment category, estimating the mass emissions reductions that would be achieved through the implementation of BARCT, and then converting the total mass emission reductions into facility mass emissions caps and shaving those emission caps over the proper timeframe calculated to implement BARCT. Each facility could then properly choose the manner in which they would achieve mass emission reduction targets at their respective facilities. They could either put controls on the identified equipment category, control emissions from other equipment at the facility, purchase emission credits from other facilities that over-controlled, or a combination of the above. In the end, whichever method was chosen, the facility that met the ever-declining emissions cap, met BARCT for the facility and should be credited with meeting BARCT for its equipment. Staff's methodology of establishing new BARCT limitations and the cost of those controls largely ignores all of the investments made to meet the legal and regulatory requirements of BARCT unless a control device was installed. Again, this arbitrarily places some facilities at a distinct disadvantage over others.

3-1
(cont'd)

The RECLAIM market driven compliance mechanism has been effective and enabled some facilities to develop new BARCT that may not have been achieved without allowing others to invest in control technology development through the purchase of credits. The purchase of credits helped to subsidize controls for other RECLAIM participants. A prime example of this is the recently adopted Rule 1117. The facilities attest that the controls were much too cost prohibitive to install without the ability to sell credits to offset the installations costs of these controls. These types of accomplishments must be accounted for in any transition from RECLAIM.

Valero, during its many years of operation under the RECLAIM program, opted to comply using a combination of allowed methodology and as one method, chose to purchase RECLAIM Trading credits. As

[1] See, e.g., Final Staff Report for the Regional Clean Air Incentives Market, October 1993, at page 1-1:
"The goal of RECLAIM is to achieve the emission reduction objectives for the Basin by providing facility operators with the flexibility to choose how to make emission reductions, thereby lowering compliance costs and providing incentives for the development and implementation of air pollution control technologies. Implementation of RECLAIM will reduce emissions from sources in the program to the same extent that they would be required to reduce emissions through implementation of existing regulations and the Air Quality Management Plan (AQMP). RECLAIM is designed to ensure that *the program achieves equivalent emission reductions*, an equal or greater level of enforcement, lower implementation costs, fewer job impacts, and no adverse public health impacts, compared to the existing program." (emphasis added)

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proposed, Rule 1109.1 does nothing to recognize this valid compliance mechanism and puts Valero at an economic disadvantage as compared to other refineries that would be subject to the new rule, when they relied on a valid regulatory program for many years. For instance, when conducting the required cost element of BARCT for FCCUs, the District simply estimates the cost of controls for the facility, without accounting for either the overall reductions the facility made over the years, including through the purchase of credits, and estimates costs of additional selective catalytic reduction (SCR) as though Valero has done nothing to control emissions. This cost is then compared to other FCCUs where the facility opted to partially control emissions through add-on controls. The result is that the District would have Valero pay twice for emission controls (credits plus SCR), while others pay only once (for SCR). To remedy this inequity, the District should either start with an assumption of the BARCT control that the District calculated when setting the RECLAIM shave with which Valero has complied or add the cost of the credits Valero purchased to the cost of the controls the District now seeks to have Valero install when conducting the cost-effectiveness evaluation. 3-1 (cont'd)

BARCT for FCCUs

To further compound the disproportionate effect of the proposed rule, the District is seeking to establish BARCT for FCCUs to be controlled under PR 1109.1 at 2ppm NOx averaged over 365 days. Valero does not believe this is achievable in a cost-effective manner.

BARCT is an emissions limitation established for a class or category of sources under California Health & Safety Code Section 40406. The District has long considered the category of source as FCCUs. In fact, the rulemaking has for the past few years centered on this principle.

The equipment category is FCCUs. There are only 5 units in the equipment category. In this source category, one FCCU is controlled by an SCR that has been installed and is reportedly on average meeting a 2 ppm limit. Two other units have SCRs installed as controls but meet an 8 ppm limit. Another has filed an application to install an SCR at 2 ppm. Rather than setting one unified emission limit for all FCCUs, the District is proposing to break up this very small equipment category into even smaller segments, essentially establishing individual emission limits for each facility. That is inconsistent with regulatory requirements under Health and Safety Code, Division 26, Part 3 (and similar provisions) for establishing BARCT, and does not meet the District's mandates to establish emissions limits for a source category. The District staff would have the unit currently at 2 ppm, remain at 2 ppm, the two units that are able to operate at 8 ppm would remain at 8 ppm, and the other two units, which currently do not have an SCR, would have to meet a 2 ppm limit. 3-2

To justify splitting this category up unit by unit, the District does a cost analysis on the four units that would have to do additional controls, and then throws half of the units out of the cost equation, labeling them "outliers" without providing a statistical basis for how this was determined. This is not an objective, scientific determination; rather, this is picking and choosing controls in order to maximize total emission reductions. There is no equitable or technically supportable way to divide this source category in a manner consistent with the Health and Safety Code (as referenced above), and thus should be looked at in the way it was intended, as a whole source category of five FCCUs, and BARCT should be established for the category as a whole. A proper BARCT analysis would look at one emission limitation for the entire class and analyze the cost for all units to comply, thus setting the BARCT limitation at the level that meets all the technological and cost requirements to establish BARCT. Any division of the category by the District places some facilities in a disadvantage compared to others, and has the District picking winners and losers rather than objectively

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establishing BARCT and requiring all affected facilities to meet that limit. By arbitrarily splitting the category into single facilities and completely discounting the considerable investments made to achieve RECLAIM program goals through purchase of credits, the proposed FCCU BARCT assessment artificially deflates the costs associated with installation of controls and meanwhile creates competitive disadvantages for the facilities that must bear these costs. 3-2 (cont'd)

Implementation Schedule

Valero appreciates staff working with the refineries to understand the complexities of engineering and installing equipment in setting BARCT deadlines. This affects technical feasibility and is a crucial element to consider in establishing BARCT. However, we are still concerned that the schedule for FCCUs is not achievable. Valero would likely rely upon the I-Plan Option 3. However, this option does not allow any additional time for the installation of controls on the FCCU. In order to meet the next scheduled turnaround, any engineering design would need to be completed and an application submitted in approximately one year. Given the limited footprint at the Wilmington Refinery, as noted above and previously communicated to the District, an engineering design is a complex task and will take more time. Therefore, we request that the percentage of emission reductions for Phase I of the I-Plan Option 3 be reduced to allow additional time to properly design a pollution control system for the FCCU. 3-3

Again, Valero is committed to working with the District to resolve all remaining RECLAIM transition issues and to obtain the emission reductions necessary in the South Coast Air Basin.

Sincerely,

Mark Phair
Vice President and General Manager

Staff Response to Comment Letter #3:

Response to Comment 3-1:

BARCT analysis for PR 1109.1 has been conducted consistent with the state law. The cost effectiveness analysis which is one of the important steps in conducting BARCT analysis, focuses on the capital costs and the operating and maintenance costs associated with achieving the proposed NOx limits. Costs associated with purchasing RTCs are not considered in the BARCT analysis since those costs are associated with the RECLAIM program and are not a compliance option under PR 1109.1. Facilities that elected to use RTCs in lieu of installing controls during RECLAIM gained the advantage of not having to pay for controls to comply with the RECLAIM shave to achieve the BARCT requirement for those units. However, there was never any guarantee that the rules would never be amended to require command-and-control BARCT. Staff's analysis indicates that the proposed BARCT limits are achievable and cost effective for Valero. The BARCT analysis accounts for existing pollution controls at the facility for each equipment category. Hence, it would be inappropriate for the BARCT analysis to account for emission reductions that occurred at a facility unrelated to PR 1109.1 for a completely different equipment category.

Response to Comment 3-2:

Staff performed a very thorough BARCT analysis consistent with the state law for PR 1109.1. One of the steps in determining BARCT for each class and category is the cost effectiveness analysis. The 2 ppmv BARCT NOx limit for the FCCU category was established based on the cost effectiveness for FCCUs. The cost effectiveness for the FCCUs with an SCR to meet the Table 1 NOx limit of 2 ppmv was greater than $100,000 per ton of NOx reduced. However, the cost effectiveness for FCCUs without an SCR to meet the Table1 NOx limit is $24,000 per ton of NOx reduced. Since an SCR will achieve 90% to 95% NOx reduction, it is technically feasible for the FCCU at Valero to achieve the 2 ppmv limit. FCCUs that have already installed SCR are properly treated as a separate source category from uncontrolled units because they cannot cost-effectively meet the same emissions limit. Establishing the class or category of source is within the discretion of the South Coast AQMD, taking into consideration the factors listed in the BARCT definition. The fact that there are only a few units in each category does not change this principle. PR 1109.1 excludes units that are installing SCR from using the Conditional Limits when it is technically feasible for those units to achieve Table 1 NOx limits. Changing the approach for one FCCU could potentially enable for other units subject to PR 1109.1 to comply only with the Table 2 conditional NOx limits when the pollution controls installed can meet the Table 1 NOx limits. Staff is also concerned that this approach allows an operator to create a "budget" of excess emissions that would result in higher NOx concentration levels from other units within the B-Plan and B-Cap. Staff is opposed to allowing this or any unit that will be installing SCR to use Table 2 conditional limits as this would result in a substantial weakening of PR 1109.1.

Response to Comment 3-3:

I-Plan Option 3 is unique in that it is available to operators that are currently achieving an emission rate of 0.02 lb/MMBtu based on 2021 annual emissions for boilers and process heaters greater than or equal to 40 MMBtu/hour. Based on discussions with the commenter, I-Plan Option 3 was modified to reduce the percent reduction target for phase 1 from 50 to 40%. This will allow the operator to install pollution controls for meeting 2 ppmv level in Table 1 for the FCCU in the second phase of the I-Plan. This refinery is smaller than the other affected facilities with lower emissions per rated capacity of the equipment. With a smaller pool of affected equipment, the facility has less flexibility with implementation timing especially when the FCCU project achieves a majority of the overall facility reduction potential.

Comment Letter #4:

September 14, 2021

Chair Benoit and Members of the Committee
Stationary Source Committee
South Coast Air Quality Management District ("South Coast AQMD")
crodriguez@aqmd.gov

Re: Agenda Item No. 2-Refinery NOx Rule

Dear Chair Benoit and Members of the Stationary Source Committee:

On behalf of the undersigned organizations, we write regarding Proposed Rule 1109.1. We have actively and in good faith participated in the rulemaking process for this rule for years. All the while, our members and supporters have continued to suffer from pollution levels from refineries that exceed what would occur if they had adopted state-of-the-art technology that has been readily available for more than a decade. We are at the point where we need to end the debate and call the question at the Board. Will this Board have the courage to adopt a life-saving regulation that will achieve more emissions reductions than any stationary source rule adopted in the last decade? We hope the answer is yes, but recent analysis conducted by staff make the decision all the more easy. 4-1

The only reason opposition is happening over this rule stems from oil companies' desires to protect their shareholders' interests. The socioeconomic analysis, which is very conservative, shows that this rule will create thousands of jobs a year. At its peak in 2032, this rule will create more than 4,400 jobs.[1] Moreover, the rule will save 370 lives, prevent more

[1] South Coast AQMD, Draft Socioeconomic Report for Draft Socioeconomic Impact Assessment For Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations Proposed Amended Rule 1304 – Exemptions Proposed Amended Rule 2005 – New Source Review for RECLAIM, at p. ES-7, *available at* 1109-1-draft-socioeconomic-impact-assessment-090721-merged.pdf (aqmd.gov).

than 6,200 asthma attacks, and prevent more than 21,000 missed workdays.[2] If passing a rule that saves hundreds of lives, keeps kids in school instead of at home with respiratory problems, and allows our economy to be even more productive is so controversial, then we have to question what this agency is doing.

We recognize that powerful and entrenched interests have spent years delaying and weakening this rule. And, we recognize that these same interests have sought to make it hard for public officials to stand for public health and job creation over the parochial interests of individual oil companies. But, too many lives are on the line, and we need you to have the courage to take this basic step that is so clearly in the public interest. This rule is not perfect, and we would like it to be much stronger. For example, this rule provides a decade to install life-saving pollution controls that should have been installed a decade or more ago. But, the more time we continue to waste in debates, the more people will get sick and die. Let's make 2021 the year the South Coast AQMD passes an important regulation to clean up warehouses and the most significant South Coast refinery pollution measure in a decade. 4-1 (con'td)

We appreciate your consideration of these comments, and we look forward to courageous debate placing the interest of public health in the forefront during the Stationary Source Committee this week.

Sincerely,

Oscar Espino Padron
Byron Chan
Adrian Martinez
Earthjustice

Jane Williams
California Communities Against Toxics

Maya Golden-Krasner
Center for Biological Diversity

Alicia Rivera
Ashley Hernandez
Alison Hahm
Julia May
Communities for a Better Environment

Chris Chavez
Coalition for Clean Air

Taylor Thomas
Jan Victor
Whitney Amaya
East Yard Communities for Environmental Justice

David Pettit
Natural Resources Defense Council

Monica Embrey
Nicole Levin
Sierra Club

cc: Wayne Nastri

[2] *Id.* at p. ES-8.

Staff Response to Comment Letter #4:

Response to Comment 4-1:

Staff appreciates the support for the proposed rule and reiterates the purpose of the rule is to reduce NOx emissions from refineries by requiring pollution control technologies to be installed on emission sources to improve the air quality in the region. As the commentator highlighted, the Socioeconomic Assessment concluded the proposed project would generate jobs and result in benefits to public health in terms of avoiding premature deaths, asthma attacks, and loss of workdays. With regard to timing, the PR 1109.1 is currently on track for the Governing Board to consider approval of PR 1109.1, and companion rules, at the November 5, 2021 Governing Board meeting.

Comment Letter #5:

Torrance Refining Company

Torrance Refining Company LLC
3700 W. 190th Street
Torrance, CA 90504
www.pbfenergy.com

September 17, 2021

VIA E-MAIL: srees@aqmd.gov

Sarah Rees, Ph.D.
Deputy Executive Officer
Planning, Rule Development & Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Comments on South Coast Air Quality Management District Staff's Proposed Rules 1109.1, 429.1 and 1304 related to the 75-Day Package released to the Public on Friday, August 20, 2021

Dear Dr. Rees:

Torrance Refining Company LLC ("TORC") is pleased to submit comments to the South Coast Air Quality Management District ("District") in response to staff's Proposed Rules 1109.1, 429.1 and 1304 related to the 75-Day Package released on August 20, 2021 ("75-Day Package"). This letter supplements TORC's previous comment letters submitted to the District on November 20, 2020, December 14, 2020, January 27, 2021, two letters on April 16, 2021, June 21, 2021, and August 4, 2021.

Rule 1109.1 Comments

(d) Emission Limits

(d)(2)(B)(ii) – *"No later than 18 months after the South Coast AQMD Permit to Construct is issued, meet the NOx and CO emission limits at the percent O2 correction and the averaging time specified in Table 2 or subdivision (k), whichever is applicable."*

A Permit to Operate could be issued as well. The District needs to clarify in this section that the NOx and CO emission limits need to be met no later than 18 months after either the Permit to Construct or the Permit to Operate is issued, not just the Permit to Construct. 5-1

Additionally, this seems to conflict with Sections (d)(8) and (d)(9). The District needs to clarify that if a refinery completes construction within 18 months consistent with Table 2, then based on the averaging period, the refiner is subject to the NOx and CO limits per Section (d)(8) and (d)(9).

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(f) Interim Emission Limits

Table 5: Interim NOx Emission Rates for Boilers and Process Heaters ≥ 40 MMBtu/hr

The District has included interim limits for "Units that are < 40 MMBtu/hr" in Table 4. Since Table 5 are interim limits for Units ≥ 40 MMBtu/hr, Units that are < 40 MMBtu/hr with CEMS should be removed from the table as they would have to meet two interim limits. 5-2

(g) Compliance Schedule

Table 6 – Compliance Date. No later than 36 months after a South Coast AQMD Permit to Construct is issued. 5-3

The District should clarify that the 36- month period in this Section means the time to construct the emission control equipment, not meet the limit as allowed per (d)(8) and (d)(9). This should be clarified in the Draft Staff Report.

(i) I-Plan, B-Plan, and B-Cap Submittal and Approval Requirement

(i)(5)(C) – *"An owner or operator shall modify an approved I-Plan, B-Plan, or B-Cap if:*

> *(iii) A higher Alternative BARCT NOx Limit will be proposed in the South Coast AQMD permit application than the Alternative BARCT NOx Limit for that unit in the currently approved I-Plan, B-Plan, or B-Cap;"* 5-4

Since the I-Plan and the B-Plan may also have a lower Alternate BARCT or Conditional NOx Limit than what was approved, the District should remove the word "higher." Further, the District should clarify that this Section applies to both BARCT NOx Limits and Conditional Limits as well.

(j) CEMS Requirements

(j)(3) – *"An owner or operator of a unit with a CEMS that measures CO at [DATE OF ADOPTION] must operate and maintain the CO CEMS pursuant to the applicable Rules 218.2 and 218.3 requirements to demonstrate compliance with the Table 1, Table 2, or Table 3 CO emissions limits and certify the CEMS within 12 months of [DATE OF ADOPTION] pursuant to the applicable Rules 218.2 and 218.3 requirements."* 5-5

The District should clarify that this section should only apply to CO CEMS that were installed to meet District Rules and Regulations. CO CEMS subject to federal rules should not be required to meet District Rules 218.2 or 218.3 or the averaging period of the rule.

(l) Diagnostic Emission Checks

This section does not include how long to conduct the Diagnostic Emission Checks. The District should clarify in this Section that the duration of the Diagnostic Emissions Checks should be consistent with the BARCT or Conditional Limit averaging periods. 5-6

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(n) Exemptions

(n)(3) – *"Low-Use Process Heater with a rated heat input capacity greater than or equal to 40 MMBtu/hour*

An owner or operator of a process heater with a rated heat input capacity greater than or equal to 40 MMBtu/hour that is fired at less than 15 percent of the rated heat input capacity on an annual basis, shall be exempt from the applicable emission limits in Table 1, Table 2, and an approved B-Plan" 5-7

The District has included low use exemptions for Boiler < 40 MMBtu/hr and Process Heaters ≥ 40 MMBtu/hr. The District should also include in Section (n)(3) Low-Use Boilers that are only used at less than 15 percent of the rated heat input capacity on an annual basis.

<u>Rule 429.1 Comments</u>

(c) Definitions

The definition of "CATALYST MAINTENANCE" should also include any ancillary equipment to the SCR system such as the NH3 injection system and the induced draft fan. 5-8

(d) Requirements

(d)(8) – *"An owner or operator of a unit equipped with a NOx post-combustion control equipment at a former RECLAIM petroleum refinery or a new petroleum refinery which has a stack or duct that exists prior to [Date of Adoption] that allows for the exhaust gas to bypass the NOx post-combustion control*

equipment and that elects to use a bypass to conduct catalyst maintenance shall:

> *(A) Not use a bypass if the unit is scheduled to operate continuously for less than five years between planned maintenance shutdowns of the unit;*
>
> *(B) Not use a bypass to conduct catalyst maintenance for more than 200 hours in a rolling three-year cycle;* 5-9
>
> *(C) Operate the unit at the minimum safe operating rate of the unit when the NOx post-combustion control equipment is bypassed;*
>
> *(D) Submit documentation from the manufacturer of the minimum safe operating rate for the unit being bypassed to the South Coast AQMD;"*

The term "minimum safe operating rate of the unit" should clearly refer to the Process Unit, not the combustion device. The minimum rate or turndown of a combustion device could be lower than the safe operating rate of the Process Unit and would cause the unit to shut down. The combustion device's operation will be dictated by the operating rate of the Process Unit. Further, the minimum safe operating rate is determined by the Refinery, not a manufacturer. Therefore, documentation should not be required.

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(f) Recordkeeping

(f)(2) – *"An owner or operator of a unit equipped with NOx post-combustion control equipment at a former RECLAIM petroleum refinery or a new petroleum refinery shall maintain on-site documentation from the manufacturer of the minimum operating temperature of the NOx post-combustion control equipment and make this information available to the South Coast AQMD upon request."* 5-10

Refineries' Title V permits include permit conditions for specific temperatures when the injection of NH3 should begin in the SCR system for optimal NOx reduction. Therefore, this requirement should also include … "unless the minimum temperature requirement is in the Refinery's permit."

Rule 1304 Comments

(f) Limited BACT Exemption

(f)(A) – *"The new or modified permit unit is located at a RECLAIM or former RECLAIM facility and is being installed or modified to comply with a South Coast AQMD rule to meet a specified NOx Best Available Retrofit Control Technology (BARCT) emission limit initially established before December 31, 2023;"* 5-11

The Draft Staff report for PAR 1304 indicates that Section (f)(1)(A) limits the BACT exemption to new or modified permit units being installed or modified at RECLAIM or former RECLAIM facilities to comply with a NOx BARCT rule to transition the NOx RECLAIM program to command-and-control regulatory structure. Therefore, it appears that the intent of this exemption is that it not only applies to BARCT emission limits, but Conditional, B-Plan and B-CAP emission limits as well. For avoidance of doubt, particularly in the permitting process, The District should clarify this Section accordingly.

* * *

In closing, as noted above, there remains proposed rule language that requires additional clarification to create rulemaking that is clear, unambiguous, and achieves the desired goal without creating undesirable effects. As noted, TORC will continue to work with District Staff to address these concerns.

Thank you for the opportunity to submit comments on the 75-day Package. We will continue to work diligently with District staff and other stakeholders to address the complex issues associated with this package.

Please note that in submitting this letter, TORC reserves the right to supplement its comments as it deems necessary, especially if additional or different information is made available to the public regarding the PR 1109.1 rulemaking process.

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If you have any questions regarding TORC's comments, please call or email me or John Sakers. Our office phone numbers are 310-212-4500 (Steve) and (310) 212-4292 (John).

Sincerely,

Steve Steach
Refinery Manager

cc: **District Staff - via e-mail and overnight delivery**

Wayne Nastri	Executive Officer
Susan Nakamura	Assistant Deputy Executive Officer
Michael Krause	Planning and Rules Manager
Michael Morris	Planning and Rules Manager

cc: **District Refinery Committee Members - via e-mail and overnight delivery**

Hon. Ben Benoit	Governing Board Chair
Hon. Larry McCallon	Governing Board Member and Refinery Committee Chair
Hon. Lisa Bartlett	Governing Board Member and Refinery Committee Member

cc: **District Governing Board Members - via overnight delivery**

Hon. Joe Buscaino	Governing Board Member
Hon. Michael A. Cacciotti	Governing Board Member
Hon. Vanessa Delgado	Governing Board Vice-Chair
Hon. Gideon Kracov	Governing Board Member
Hon. Shelia Kuehl	Governing Board Member
Hon. Veronica Padilla-Campos	Governing Board Member
Hon. V. Manuel Perez	Governing Board Member
Hon. Rex Richardson	Governing Board Member
Hon. Carlos Rodriguez	Governing Board Member
Hon. Janice Rutherford	Governing Board Member

Staff Response to Commenter Letter #5:

Response to Comment 5-1:

Staff clarified the language to include the issuance of a permit to operate. Depending on the project and equipment, a permit to construct and/or permit to operate could be issued; therefore, staff will add both permit types throughout the proposed rule to ensure it is clear and accurate when required timelines are triggered.

Response to Comment 5-2:

Staff concurs that the language in the preliminary draft rule includes two separate interim limits for boilers and heaters <40MMBtu/hour that operate with a certified CEMS. Staff proposes to revise the language to clarify that the facility can elect to comply with either the 40 ppmv interim limit or the 0.03 pound per million Btu emission rate for boilers and process heaters <40MMBtu/hour that operate with a certified CEMS. The rule will include a reporting requirement for the facilities to inform the South Coast AQMD which interim emission limit the boilers and process heaters will be bound to comply with.

Response to Comment 5-3:

Staff modified the proposed rule to clarify that the implementation timeframe to comply with the limits includes construction, commissioning, and initial source test but not the additional time allowed under (f)(8) and (f)(9).

Response to Comment 5-4:

A facility would not be required to modify the I-Plan, B-Plan, or B-Cap if they established a lower NOx limit in the permit than was included in the I-Plan, B-Plan, or B-Cap. A facility may choose to modify the plans but that will not be a requirement under PR 1109.1. A lower NOx limit would result in the even lower emission than in the approved plan; therefore, a modification is not required. A higher NOx limit could require a facility to lower NOx limits for a unit or units in the approved plan; therefore, a modification is required.

Regarding the conditional limits, all NOx limits specified in the B-Plan or B-Cap are alternative NOx limits so by definition conditional limits do not have to be specifically mentioned in subparagraph (d)(5)(C).

Response to Comment 5-5:

Staff initially proposed requiring CO CEMS on all units; however, staff revised the proposed rule to only require units with existing CO CEMS to maintain the CEMS. PR 1109.1 is focused on NOx emission reductions while not increasing CO emissions. The CO CEMS requirement was removed to reduce costs for CO compliance to maximize the rule's ability to achieve NOx reductions; however, there is little to no additional cost for facilities with an existing CO CEMS to continue to use that CEMS. In addition, the operation of the CO CEMS to demonstrate CO limit compliance will allow the facility to not conduct annual source tests to determine CO emissions. Thus, any CO CEMS already installed on a unit subject to PR 1109.1 should maintain the CEMS to demonstrate compliance with the rule.

Response to Comment 5-6:

Staff concurs with this comment and will clarify the rule to include a 30-minute duration time for the diagnostic check.

Response to Comment 5-7:

PR 1109.1 exempts units with low-use or low-emitting characteristics because they can be very costly to retrofit. Exempting those units reduces the overall cost-effectiveness for the class and category. Staff also evaluates individual units with high cost-effectiveness even if the class and category overall is cost-effective. While not a legal requirement, this assessment is conducted to exclude costly projects that will not achieve significant emission reductions. Staff's evaluation of the boiler category showed the class and category to be very cost effective. However, staff went further and included conditional limits (7.5 ppmv) to address a few units that are achieving very close to the proposed NOx limit of 5 ppmv that would be costly to retrofit. Those units were cost outliers. When evaluating the conditional limits, staff did not identify any other units as cost outliers. Boilers at petroleum refineries are very cost effective to retrofit because they have very high NOx emissions, PR 1109.1 will not include any further exemptions for boilers.

Response to Comments 5-8 through 5-10:

Please see staff's response in the Staff Report for PR429.1.

Response to Comment 5-11:

Please refer to response to comment in the Staff Report for PAR 1304.

Comment Letter #6:

WSPA

Patty Senecal
Senior Director, Southern California Region

September 17, 2021

Mr. Michael Krause
Manager, Planning and Rules
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Via e-mail at: mkrause@aqmd.gov

Re: SCAQMD Proposed Rule 1109.1, Emissions Of Oxides Of Nitrogen From Petroleum Refineries And Related Operations
WSPA General Comments on Draft Rule Language (August 20, 2021 Revision)

Dear Mr. Krause,

Western States Petroleum Association (WSPA) appreciates the opportunity to participate in the Working Group Meetings (WGMs) for South Coast Air Quality Management District (SCAQMD or District) Proposed Rule 1109.1, Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR1109.1). This proposed rulemaking is part of the District's larger project to transition facilities in the Regional Clean Air Incentives Market (RECLAIM) program for NO_X emissions to a command-and-control structure (i.e., the "RECLAIM Transition Project"). WSPA is a non-profit trade association representing companies that explore for, produce, refine, transport, and market petroleum, petroleum products, natural gas, and other energy supplies in five western states including California. WSPA has been an active participant in air quality planning issues for over 30 years. WSPA-member companies operate petroleum refineries and other facilities in the South Coast Air Basin that are within the purview of the RECLAIM Program administered by the SCAQMD and will be impacted by PR1109.1.

On August 20, 2021, SCAQMD released Preliminary Draft Rule Language for PR1109.1 (Draft Rule).[1] The District has requested written comments on this rule by September 17, 2021. WSPA will be providing written comments on PR429.1 and PR1304, both of which are critical to the PR1109.1 rulemaking package. With this letter, WSPA is providing comments on the PR1109.1 Preliminary Draft Rule Language. In addition, we are attaching a redlined version of the District's August 20 version of PR 1109.1 rule based on the below comments. WSPA understands that SCAQMD is working on revising the Draft Rule, and we may provide comments on the revised language after it has been released.

1. **Dates and deadlines for compliance are presented in numerous sections of the proposed rule. For clarity, all compliance dates should be presented in Section (g), Compliance Schedule. Additionally, all compliance dates for meeting emission limits should be based on the date of issuance of a Permit to Construct.** 6-1

[1] SCAQMD Proposed Rule 1109.1 Preliminary Draft Rule Language, released August 20, 2021. Available at SCAQMD PR1109.1 page.

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Section (g) of the rule provides requirements for the compliance schedule. However, a number of dates and deadlines are presented in other sections of the proposed rule.

For example, Section (d)(2)(B)(ii) states:

> *No later than 18 months after the South Coast AQMD Permit to Construct is issued, meet the NOx and CO emission limits at the percent O_2 correction and the averaging time specified in Table 2 or subdivision (k), whichever is applicable.*

All dates for permit application submission, compliance, etc. should be consolidated in Section (g) for clarity and to ensure there are no internal conflicts. Affected sections include, but are not limited to: (d)(2)(B), (d)(3), (d)(4), (d)(8), (d)(9), (e)(1)(A), and (e)(2)(A).

Additionally, dates for compliance with the rule's emissions standards should be based on the date a permit to construct/operate is issued. For example, Section (g)(2)(I) states: 6-1 (cont'd)

> *(I) For an owner or operator with an approved B-Cap, demonstrate compliance with the emissions requirements and all other requirements no later than the compliance date for Phase I in I-Plan Option 4 and no later 54 months from South Coast AQMD Permit Application Submittal Date for all other phases of the selected iPlan option in Table 6 to meet the Phase I, Phase II, or Phase III Facility BARCT Emission Targets.*

A facility has no control over whether the District issues a permit within a specified time period. Therefore they should not be held to a compliance date that is dependent on an application submittal date. All compliance requirements that are based on permit issuance should be tied to a time period after permit issuance. We have provided proposed language changes for each of these sections in the attached redlined version of the proposed rule.

2. **In multiple sections the Draft Rule language requires that a facility submit a complete application. The word "complete" has a specific regulatory meaning. Having an application deemed "complete" by the District is outside the control of the facility. This language should be removed from the rule.**

   Several sections in the Draft Rule language require the facility submit a "complete" application package. For example (d)(2)(B) states:

   > *(B) Before July 1, 2022, submit a complete South Coast AQMD permit application to apply for a permit condition that limits the NOx emissions to the applicable levels specified in Table 2.*

   SCAQMD Rule 210 provides the requirements for applications for a permit required under Rules 201, 203, and 208. It states: 6-2

   > *(b) The Executive Officer shall notify the applicant in writing within 30 calendar days of the receipt of an application for a permit, pursuant to Rule 201, as to whether or not the application contains sufficient information to be deemed complete. Upon receipt of any resubmittal or additional information after the application has been deemed incomplete a new 30-day period shall begin during which the Executive Officer shall determine and notify the applicant regarding completeness of the application…*

   Because the word "complete" has a specific regulatory meaning, and the onus to deem an application complete lies with the District, the word "complete" should be removed from language requiring a facility to submit an application.

3. **Section (d)(2). Under section (d)(2)(C) the District is proposing that an owner or operator shall meet the Conditional NOx and CO Emission Limits in Table 2 if the unit is listed in Table D-1 or D-2. Owners or operators choosing to comply with a B-Plan or** 6-3

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B-Cap will have the flexibility to choose the alternative endpoint for the emission unit, including for units listed in Tables D-1 or D-2.

WSPA recommends the language be updated as follows:

(d) Conditional NOx and CO Emission Limits

(2) An owner or operator of a ~~u~~Unit ~~is eligible~~ may elect to meet the NOx and CO emission limits in Table 2~~,~~ in lieu of the NOx and CO emission limits in Table 1 provided: 6-3 (cont'd)

(C) Notwithstanding subparagraph (d)(2)(A) ~~and (d)(2)(B)~~, ~~an owner or operator shall meet~~ the Conditional NOx and CO Emission Limits in Table 2 apply to a Unit in lieu of the NOx and CO Emission Limits in Table 1 if:

4. **Section (d)(2)(A)(i) could curtail the option to comply with Table 2 limits for any unit issued a permit on or after December 4, 2015 for installation of a post combustion control device for the unit. This creates a potential concern for stranded assets resulting from projects implemented as a result of the 2015 Amendments to Regulation XX (i.e. the RECLAIM shave). WSPA recommends the language be altered to eliminate this condition.**

Under Section (d)(2)(A), the District is proposing:

(A) An owner or operator of a unit is eligible to meet the NOx and CO emission limits in Table 2, in lieu of the NOx and CO emission limits in Table 1 provided:

(i) The Executive Officer has not issued a Permit to Construct on or after December 4, 2015 for the installation of a post combustion control device for the unit; 6-4

Companies have instigated emission control projects in response to the 2015 RECLAIM amendments. Facilities were not required to meet a specified endpoint for the RECLAIM shave. Therefore, a project may be underway or completed that reduces NOx emissions to below the Table 2 Conditional Limit, but not as low as the Table 1 BARCT Limit. The requirement above results in the potential for stranded asset issues on recently installed NOx control equipment. WSPA recommends the language be updated as follows:

(A) An owner or operator of a ~~u~~Unit ~~is eligible~~ may elect to meet the NOx and CO emission limits in Table 2~~,~~ in lieu of the NOx and CO emission limits in Table 1 provided:

(i) The Executive Officer has not issued a Permit to Construct with an emission limit at or below the Table 1 NOx emission limit on or after December 4, 2015 for the installation of a post combustion control device for the unit;

5. **Sections (d)(3)(A) and (d)(4)(A) would require that operators of Boilers and Process Heaters <40 MMBtu/hr have a SCAQMD permit that includes an enforceable emission limit before January 1, 2023. While a facility can apply for a permit by a certain date, they do not control when the permit is issued by SCAQMD. WSPA understands from PR1109.1 WGM #25 that SCAQMD intends to revise the language in (d)(3) and (d)(4) to include a permit submittal deadline rather than requiring units to have a permit by a certain date. WSPA agrees with this change.** 6-5

WSPA recommends the language be altered as follows:

(A) ~~Before January 1, 2023, have a South Coast AQMD Permit that includes~~ Submit a South Coast AQMD Permit application by no later than January 1, 2023 requesting ~~an enforceable~~ emission limits ~~that does~~ not to exceed 40 ppmv NOx and 400 ppmv

CO, at three percent O_2 correction, as demonstrated pursuant to ~~and limits~~ the averaging times specified in ~~to~~ Table 1 or subdivision (k), whichever is applicable. 6-5 (cont'd)

6. **Section (d)(4). The District has proposed that existing refinery heaters < 40 MMBtu/hr meet an initial BARCT limit of 40 ppmv NO_X pursuant to paragraph (d)(4) and Table 4 (Interim NO_X and CO Emission Limits). While these limits are proposed to go into force shortly after rule adoption, the District has not demonstrated whether the existing heaters in the category can meet this limit without new emission controls.**

   Under Section (d)(4)(A), the District is proposing:

   (4) Process Heaters with Rated Heat Input Less Than 40 MMBtu/hour An owner or operator of a process heater with a rated heat input capacity less than 40 MMBtu/hour shall:

   (A) Before January 1, 2023, have a South Coast AQMD Permit that includes an enforceable emission limit that does not exceed 40 ppmv NOx and 400 ppmv CO at three percent O2 correction and limits the averaging times to Table 1 or subdivision (k), whichever is applicable; 6-6

   These same NO_X and CO limits are also proposed as Interim Limits in Table 4 of the rule, so facilities would be required to comply with them shortly after rule adoption.

   The District previously acknowledged that some of the existing heaters in the category do not meet this level of emissions. At WGM #14, units in the category were reported to have current NO_X emissions ranging from 5 to 100 ppmv.[2] This was also acknowledged by the District at WGM #25.[3] The District needs to determine how many units are likely to require new emissions controls.

7. **The District has not completed the cost effectiveness analyses required to establish a 40 ppm NO_X BARCT standard for refinery heaters < 40 MMBtu/hr category.**

   As discussed above, there appear to be a number of heaters in the category that currently do not meet the proposed standard of 40 ppmv NO_X (based on a 2-hr average). The District has not provided stakeholders an assessment of the potential compliance costs or cost effectiveness. To the contrary, the District claimed there would be zero compliance cost for heaters < 20 MMBtu/hr to meet a 40 ppmv NO_X level, and negligible costs (i.e., \$3,900/tpy) for heaters rated 20-40 MMBtu/hr to meet a 30 ppmv NO_X level.[4] 6-7

   Based on recommendations from the District's third-party expert (i.e., Norton Engineering Consultants, NEC), the District later revised its BARCT proposal for the 20-40 MMBtu/hr heaters category to 40 ppmv NO_X and combined it with the <20 MMBtu/hr category.[5] The District has not presented stakeholders with a revised analysis of compliance costs or cost effectiveness for either the two original categories, or the now combined category. This is necessary to establish BARCT.

[2] SCAQMD PR1109.1 WGM #14 Presentation, August 27, 2020. Available at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm-14-ab617-community.pdf?sfvrsn=22.
[3] SCAQMD PR1109.1 WGM #25, September 15, 2021, slides 17-18. Available at http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1_wgm25_presentation.pdf?sfvrsn=10.
[4] [4] SCAQMD PR1109.1 WGM #14 Presentation, August 27, 2020. Available at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm-14-ab617-community.pdf?sfvrsn=22.
[5] SCAQMD PR1109.1 WGM #16 presentation, Slides 19-22, December 10, 2020, Available at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm16.pdf?sfvrsn=4

8. The proposed Interim Limits for the <40 MMBtu/hr heater category may need to be revised pursuant the District's "Guiding Principles" for Interim Limits.

For Interim Limits, District's outlined the following "Guiding Principles:" [6]

- "Interim limits would reflect current operating conditions until BARCT emission limits are achieved and ensure enforceable emission limits are in place;
- "Interim limits are not an interim step down to BARCT emission limits;
- "Interim limits will apply to individual units and ensure RACT requirements are being met; and
- Interim limits will be incorporated in PR1109.1 for units that have compliance dates after January 1, 2024."

In the case of the <40 MMBtu/hr heater category, the District is proposing Interim Limits (Table 4) which are identical to the initial BARCT limits pursuant to Section (d)(4). But as noted above, these may not actually represent "hold the line" levels for some of the heaters in the category. The District needs to consider whether different (i.e., higher) Interim Limits are needed to accomplish the objectives laid out in the Guiding Principles. 6-8

9. Sections (d)(3)(C) and (d)(4)(C). The District has proposed that existing refinery boilers and heaters <40 MMBtu/hr meet a more stringent deferred BARCT limit of 5 ppmv and 9 ppmv NOx, respectively. The District has not completed the analyses required to establish either of these limits as a BARCT standard.

Under Section (d)(3)(C), the District is proposing:

(3) Boilers with Rated Heat Input Less Than 40 MMBtu/hour

An owner or operator of a boiler with a rated heat input capacity less than 40 MMBtu/hour shall…

(C) No later than six months after an owner or operator cumulatively replaces either 50 percent or more of the burners in a boiler or replaces burners that represent 50 percent or more of the heat input in a boiler, where the cumulative replacement begins from July 1, 2022, shall: 6-9

(i) Submit a complete South Coast AQMD permit application to impose a 5 ppmv NOx emission limit and a 400 ppmv CO emission limit at three percent O2 correction that limits the averaging times to Table 1 or subdivision (k), whichever is applicable; and

(ii) Meet the emission limits pursuant to clause (d)(3)(C)(i) no later than 36 months after a South Coast AQMD Permit to Construct is issued.

Under Section (d)(4)(C), the District is proposing:

(4) Process Heaters with Rated Heat Input Less Than 40 MMBtu/hour

An owner or operator of a process heater with a rated heat input capacity less than 40 MMBtu/hour shall…

(C) Effective [TEN YEARS AFTER DATE OF ADOPTION], no later than six months after an owner or operator cumulatively replaces either 50 percent or more of the burners on a process heater of replaces burners that represent 50 percent or more of the heat input in a process heater, where the

[6] PR1109.1 WGM #21 presentation, Slide 27, May 27, 2021. Available at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1_wgm21_presentation-mtgversion.pdf?sfvrsn=12

> *cumulative replacement begins [FIVE YEARS AFTER DATE OF ADOPTION] shall:*
>
> *(i) Submit a complete South Coast AQMD permit application to inpose 9 ppmv NOx emission limit and a and 400 ppmv CO emission limit at three percent O2 correction and limits the averaging times to Table 1 or subdivision (k), whichever is applicable; and*
>
> *(ii) Meet the emission limits pursuant to clause (d)(4)(C)(i) no later than 36 months after a South Coast AQMD Permit to Construct is issued.*

The District has not completed the cost-effectiveness analyses required to establish either of these deferred BARCT standards. California Health & Safety Code §40406 defines BARCT as "an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and *economic impacts* by each class or category of source" (*Emphasis added*).[7] The District has not provided stakeholders an actual assessment of the potential compliance costs or the cost-effectiveness for these units. Instead, it has established requirements which would arbitrarily dictate when equipment will be deemed to have reached an "end-of-useful life," and then claims that facilities would have no additional cost because "(m)ajority of cost will already be incurred by facility upon replacement."[8]

6-9 (cont'd)

Additionally, for process heaters <40 MMBtu/hr, the District has taken the position that it can establish a "technology forcing" BARCT standard based on emerging technologies which it reasonably expects to be available at some future time. Regardless, the District would still be obligated to demonstrate technical feasibility prior to imposing such a BARCT standard.

The District has proposed this emerging technology standard based on burner technology products which the District hopes may be available at some future date. But the District has noted at several PR1109.1 working group meetings that these burner products are still in the research & development (R&D) phase and are not commercially available. The District has pushed the effective date for this 9 ppmv NOx requirement in Section (d)(4)(B) to "ten years after date of adoption," but this is an arbitrary and uncertain date. The District has no way to know whether these products will achieve commercially readiness within 10 years, or ever.

WSPA has previously commented that any such technology forcing standard must be subject to a District-led technology review step before the BARCT standard becomes effective. The stationary sources subject to PR1109.1 are not involved with the R&D or commercialization of the products on which the District's standard would rely, and they have no ability to ensure it happens on an arbitrary District timetable.

In establishing a BARCT standard, the District must follow the Health & Safety Code requirements to demonstrate technical feasibility and cost-effectiveness. And in this case, the District has not met either obligation.

10. Section (e)(2)(B)(ii). The language in Section (e)(2)(B)(ii) would significantly restrict the flexibility for choosing emission limits within the B-Cap option. WSPA recommends that the language in this section be removed from the rule. 6-10

Under Section (e)(2)(B), the District has proposed:

[7] California Health and Safety Code §40406. Available at: https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=40406.&lawCode=HSC

[8] SCAQMD, Preliminary Draft Staff Report for Proposed Rule 1109.1, released August 20, 2021, page 4-7 et seq. Available at SCAQMD PR1109.1 page.

(2) An owner or operator of a facility with six or more units that elects to meet the NOx and CO emission limits in an approved B-Cap in lieu of meeting Table 1 and Table 2 NOx concentration limits shall…

(B) Select an Alternative BARCT NOx Limit for Phase I, Phase II, and Phase III to meet the respective Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions where the Alternative BARCT NOx Limit shall not exceed… 6-10 (cont'd)

(ii) The Conditional NOx and CO limit in Table 2, for any unit that is meeting a Conditional NOx and CO Emission Limit pursuant to subparagraphs (d)(2)(A) or (d)(2)(B).

The purpose of the B-Cap is to allow facilities the flexibility to choose an Alternative BARCT NOx Limit. Therefore, facilities should not be required to meet the Conditional NOx Limit in Table 2. WSPA recommends that the language in Section (e)(2)(B)(ii) be removed from the rule.

11. Section (e)(2)(D). The BARCT endpoints for units should be based on the category of the equipment, irrespective of whether the facility is choosing to comply with the Table 1 and Table 2 standards, as applicable, or to utilize the B-Plan or B-Cap alternative compliance approaches. Thus, units subject to Table 1 emission limits should be represented as Table 1 units, and units subject to Table 2 emission limits should be represented as Table 2 units for the purpose of calculating emission reductions from decommissioning.

WSPA recommends the language in Section (e)(2)(B) be updated as follows: 6-11

(2) An owner or operator of a facility with six or more units that elects to meet the NOx and CO emission limits in an approved B-Cap in lieu of meeting Table 1 and Table 2 NOx concentration limits shall:

(D) For any ~~u~~Unit that is permanently decommissioned, represent the decommissioned ~~u~~Unit as Table 1 or Table 2 NOx emissions, as applicable, in the Phase I, Phase II, ~~or~~ and if applicable Phase III Facility BARCT Emission Target in an approved B-Cap, ~~and for the unit that is decommissioned the owner or operator shall~~:

12. Section (e)(2)(F)(iv). The language in Section (e)(2)(F)(iv) would impose additional restrictions for using emission reductions resulting from decommissioning units to meet the Facility BARCT Emission Target. This requirement does not result in additional emission reductions from facilities choosing the B-Cap option. Thus, the language should be removed from the rule.

Under Section (e)(2)(F)(iv), the District is proposing: 6-12

(2) An owner or operator of a facility with six or more units that elects to meet the NOx and CO emission limits in an approved B-Cap in lieu of meeting Table 1 and Table 2 NOx concentration limits shall…

(F) Not add a new unit that will be subject to this rule that increases the facility emissions above applicable Phase I, Phase II, or Phase III Facility BARCT Emission Target, unless…

(iv) The total amount of NOx emission reductions from units that were decommissioned, represents 15 percent or less of Final Phase Facility BARCT Emission Target in an approved B-Cap.

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Facilities operating under an approved B-Cap should be allowed to take credit for all emission reductions from decommissioned units. Therefore, the language in Section (e)(2)(F)(iv) should be removed from the rule. 6-12 (cont'd)

13. Section (f). Boilers and heaters rated at <40 MMBtu/hr operating with NOx CEMS are required to meet Interim Emission Limits listed in both Sections (f)(1) and (f)(2)(A), and therefore are double regulated. WSPA recommends that these units be subject to either the Limits in Table 4 or the Limits in Table 5, but not both. 6-13

14. Section (g). The language in Section (g)(1) addresses compliance schedule for owners or operators of a unit that is required to meet the Table 1 emission limits. Section (g) does not address the compliance schedule for units that will meet the Table 2 Conditional Limits. WSPA recommends that the compliance schedule for units meeting the Conditional Limits be moved from Section (d)(2)(B) to a new Section (g)(2).

WSPA recommends that the requirements currently listed in Section (d)(2)(B) be moved to a new Section (g)(2) to address the compliance schedule for units complying with Table 2 Conditional Limits. 6-14

(g)(2) An owner or operator that meets the conditions in subparagraph (d)(2)(A) that elects to meet the NOx and CO emission limits in Table 2 in lieu of the NOx and CO emission limits in Table 1 shall:

(A) Before July 1, 2022, submit a South Coast AQMD permit application to apply for a permit condition that limits the NOx emissions to the applicable levels specified in Table 2; and

(B) No later than 18 months after the South Coast AQMD Permit to Construct is issued, meet the NOx and CO emission limits at the percent O2 correction and the averaging time specified in Table 2 or subdivision (k), whichever is applicable.

15. Section (i)(4) provides the criteria for approval of the I-Plan, B-Plan, or B-Cap. As written, the language could be interpreted to allow for SCAQMD disapproval for any reason. WSPA recommends that the language be revised such that the plan will be approved provided it meets the listed criteria. WSPA also recommends that a timeframe for approval or disapproval of a plan be added to the rule language.

Under Section (i)(4), the District is proposing:

(4) The Executive Officer will notify the owner or operator in writing whether the I-Plan, B-Plan, or B-Cap is approved or disapproved based on the following criteria… 6-15

The current rule language could be interpreted to allow for SCAQMD disapproval for any reason, resulting in a source being required to meet the Table 1 and Table 2 limits. The rule language should specify that approval will be granted if the listed criteria are met. Additionally, the rule language should specify a timeline for response from the District for approval or disapproval of a Plan. WSPA recommends the language in Section (i)(4) be updated as follows.

(4) The Executive Officer will notify the owner or operator in writing within 30 days whether the I-Plan, B-Plan, or B-Cap is approved or disapproved. An I-Plan, B-Plan, or B-Cap will be approved provided it meets ~~based on~~ the following criteria…

Western States Petroleum Association 1415 L Street, Suite 900, Sacramento, CA 95814 805.701.9142 wspa.org

16. Section (k) addresses source test requirements. Quarterly source testing is onerous and inconsistent with rules applicable to similar equipment. WSPA recommends that the required source test frequency be once/year.

Section (k) provides source test requirements. Table 7, Source Testing Schedule for Units without Ammonia Emissions in the Exhaust, and Table 8, Source Testing Schedule for Units with Ammonia Emissions in the Exhaust provide the source test schedule. Depending on whether a unit is operated with or without various pollutant CEMS, the rule requires source testing quarterly during the first 12 months of being subject to a Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit (as applicable), and quarterly thereafter. The tables state that source tests may be conducted annually after the first 12 months if four consecutive quarterly source tests demonstrate compliance with emission limits. 6-16

Rule 1146, Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters requires source testing every 3 years for units with a rated heat input capacity ≥10 MMBtu/hr and every 5 years for units with a rated heat input capacity 5 – <10 MMBtu/hr. Rule 1146.1 Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, requires source testing every five years for units with a rated heat input capacity >2 - <5 MMBtu/hr. Rule 1134, Emissions of Oxides of Nitrogen from Stationary Gas Turbines, requires source testing on gas turbines every 1-3 years, depending on annual emissions of the unit.

The quarterly source tests in the Draft Rule language would be onerous and costly. The regulations for similar equipment require source testing every 1 – 5 years depending on equipment type. WSPA recommends that the required source test frequency be reduced to once per year.

17. Section (k)(3) addresses the source test schedule for units with ammonia emissions in the exhaust. PR 1109.1 does not limit ammonia emissions and does not require ammonia CEMS. Therefore, all items related to ammonia, including source test requirements, should be handled during the permitting process. Section (k)(3) should be removed from the rule. 6-17

18. Attachment B, Section B-2. It is understood that the intent of Section (d)(2)(C) and, by reference, Tables D-1 and D-2 is that these units would be Conditional Limit units by rule. To achieve this effect, the wording in Section B-2 should be revised.

WSPA recommends the language in Attachment B, Section B-2 be updated as follows:

(B-2) Final Phase Facility BARCT Emission Target

The Final Phase Facility BARCT Emission Target is the Phase II Facility BARCT Emission Target for an I-Plan option with two phases or the Phase III Facility BARCT Emission Target for an I-Plan option with three phases. The Final Phase Facility BARCT Emission Target is used to establish the Phase II or Phase III BARCT Emission Target for a B-Cap. To establish the Final Phase Facility BARCT Emission Target, the owner or operator must select whether ~~if~~ the basis of the emission target for each ~~u~~Unit will be based on Table 1 or Table 2 NOx concentration limits. The owner or operator shall only select Table 2 NOx concentration limits if the requirements of subparagraphs (d)(2)(A) and (g)(2) for the Conditional NOx Limits are met or if the ~~u~~Unit is identified pursuant to subparagraph (d)(2)(C) ~~in~~ and Attachment D. For all other ~~u~~Units, the owner or operator shall use NOx limits from Table 1 as the basis of the Facility BARCT 6-18

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Emission Target. To calculate the Final Phase Facility BARCT Emission Target for B-Cap, the owner or operator shall use NOx concentration limits from ~~of~~ Table 1 for the ~~u~~Units that will be decommissioned. 6-18 (cont'd)

19. Attachment B, requires that the Facility BARCT Emission Target be reduced by 10 percent for a B-Cap program. While WSPA does not agree with the inclusion of this additional environmental benefit, if it remains, the rule should provide the flexibility to meet the benefit by other means.

In Attachment B, Section B-4, the District is proposing:

(B-4) Calculating Phase I, Phase II, or Phase III Facility BARCT Emission Target

The Phase I, Phase II, or Phase III Facility BARCT Emission Targets are the total NOx mass emissions per facility based on the Total Facility NOx Emission Reductions and the Percent Reduction Target of Phase I, Phase II or Phase III of an I-Plan option in Table 6. For a B-Cap, each phase Facility BARCT Emission Targets shall be reduced by 10 percent.

U.S. EPA's Economic Incentive Program (EIP) Guidance[9] indicates that the B-Cap is not an EIP. For example, when describing the types of discretionary EIPs, the EIP Guidance includes statements such as the following:

- An EIP may be an emission trading program, a financial mechanism program, a program such as a clean air investment fund (CAIF) that has features of both trading and financial mechanism programs, or a public information program.[10] 6-19
- The four general types of EIPs are emission trading programs, financial mechanisms, CAIFs, and public information programs.[11]
- Unlike traditional CAA regulatory mechanisms, emission trading involves more than one party.[12]

Since the B-Cap does not involve trading, and clearly does not qualify as any of the other types of EIPs covered by the EIP Guidance, the B-Cap should not be subject to review under the EIP Guidance.

While the US EPA EIP gudaince does generally require an additional environmental benefit to be included for certain applicable programs,the guidance "recognizes that the type of demonstration appropriate will depend on the goals and characteristics of the EIP [being] implemented."[13] Other options for providing environmental benefit, in addition to the 10% additional emissions reduction, are as follows:

- Showing greater or more rapid emission reductions due to trading (e.g., early reductions)
- Reducing emission reductions generated by program participants by at least 10 percent
- Showing other environmental management improvements

[9] Improving Air Quality with Economic Incentive Programs, US EPA, January 2001. Available at: https://www.epa.gov/sites/default/files/2015-07/documents/eipfin.pdf. Accessed: September 2021.
[10] *Id*. at p. 15.
[11] *Id.* at p. 18
[12] *Id.* at p. 78.
[13] *Id.* at p. 56

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- Improved administrative mechanisms (for example, your EIP achieves emissions reductions from sources not readily controllable through traditional regulation)
- Reduced administrative burdens on regulatory agencies that lead to increased environmental benefits through other regulatory programs
- Improved emissions inventories that enhance and lend increased certainty to State planning efforts
- The adoption of emission caps which over time constrain or reduce growth-related emissions beyond traditional regulatory approaches.
- For multi-source cap and trade program or a single source cap and trade program, includes a declining cap

If the requirement remains, the language should be updated to reflect the flexibility to meet the environmental benefit requirement by other means, as allowed in the EPA EIP Guidance Document.

6-19 (cont'd)

20. **Additional minor revisions and language clarifications are provided in the attached redline version of the Preliminary Draft Rule.** 6-20

WSPA appreciates the opportunity to provide these comments related to PR1109.1. We look forward to continued discussion of this important rulemaking. If you have any questions, please contact me at (310) 808-2144 or via e-mail at psenecal@wspa.org.

Sincerely,

Patty Senecal

Attachment

Cc: Wayne Nastri, SCAQMD
Susan Nakamura, SCAQMD

Proposed Draft Rule

(Adopted TBD)
Revision Date 8-20-21

PROPOSED RULE 1109.1. EMISSIONS OF OXIDES OF NITROGEN FROM PETROLEUM REFINERIES AND RELATED OPERATIONS

(a) Purpose
The purpose of this rule is to reduce emissions of oxides of nitrogen (NOx), while not increasing carbon monoxide (CO) emissions, from units at petroleum refineries and facilities with related operations to petroleum refineries.

(b) Applicability
The provisions of this rule shall apply to an owner or operator of units at petroleum refineries and facilities with related operations to petroleum refineries.

(c) Definitions

(1) ALTERNATIVE BARCT NOx LIMIT ~~FOR PHASE I, PHASE II, OR PHASE III~~ means a ~~the unit~~Unit specific NOx concentration limit that is selected by the owner or operator to achieve the Phase I, Phase II, or if applicable Phase III, Facility BARCT Emission Target in the aggregate in a~~the~~ B-Plan or B-Cap, where the NOx concentration limit ~~will~~ includes the corresponding percent O_2 correction and ~~determined based on~~ the averaging time specified in Table 1 or subdivision (k), whichever is applicable.

(2) ASPHALT PLANT means a ~~f~~Facility that processes crude oil into asphalt.

(3) BASELINE FACILITY EMISSIONS means the sum of all the Baseline Unit Emissions at a Facility as calculated according to Attachment B of this rule.

(4) BASELINE UNIT EMISSIONS means ~~a Unit's~~ emissions from a Unit as reported in the 2017 NOx Annual Emissions Report, or another representative year, as approved by the Executive Officer.

(5) BARCT EQUIVALENT COMPLIANCE PLAN (B-PLAN) means a compliance plan that allows an owner or operator to select Alternative BARCT NOx ~~concentration l~~Limits for all Units subject to this rule that are equivalent, in the aggregate, to the NOx concentration limits specified in Table 1 and Table 2.

(6) BARCT EQUIVALENT MASS CAP PLAN (B-CAP) means a compliance plan that establishes a Facility mass emission cap ~~for all units subject to this rul~~that, in the aggregate, is~~are~~ equivalent to or less than the Final Phase Facility BARCT Emission Target.

(7) BIOFUEL PLANT means a Facility that produces fuel by processing feedstocks including vegetable oil, animal fats, and tallow.

(8) BOILER means any Unit that is fired with gaseous fuel and used to produce steam. For the purpose of this rule, ~~b~~Boiler does not include CO ~~b~~Boilers.

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(9) CO BOILER means a ~~boiler~~ Unit that is fired with gaseous fuel with an integral waste heat recovery system used to oxidize CO-rich waste gases generated by the FCCU.

(10) CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) is as defined by Rule 218 – Continuous Emission Monitoring.

(11) DUCT BURNER means a device in the heat recovery steam generator of a Gas Turbine that combusts fuel and adds heat energy to the ~~g~~Gas ~~t~~Turbine exhaust.

(12) FACILITIES WITH RELATED OPERATIONS TO PETROLEUM REFINERIES includes Asphalt Plants, Biofuel Plants, Hydrogen Production Plants, ~~p~~Petroleum ~~c~~Coke ~~c~~Calcining ~~f~~Facilities, Sulfuric Acid Plants, and Sulfur Recovery Plants.

(13) FACILITIES WITH THE SAME OWNERSHIP means Facilities and their subsidiaries, Facilities that share the same board of directors, or Facilities that share the same parent corporation.

(14) FACILITY means, for the purpose of this rule, any ~~u~~Unit or group of ~~u~~Units which are located on one or more contiguous properties, in actual physical contact or separated solely by a public roadway or other public right-of- way, and operate under one South Coast AQMD Facility ID or Facilities ~~w~~With ~~t~~The Same Ownership.

(15) FINAL DETERMINATION NOTIFICATION means the notification issued by the Executive Officer to a RECLAIM ~~f~~Facility designating that the ~~f~~Facility is no longer in the NOx RECLAIM program.

(16) FINAL PHASE FACILITY BARCT EMISSION TARGET means the total mass emissions remaining per Facility calculated based on the applicable ~~Table 1~~ emission limits in Table 1 or Table 2 ~~conditional emission limits~~ and the Baseline Emissions.

Commented [A1]: "Baseline Emissions" is not defined.

(17) FLARE means, for the purpose of this rule, a combustion device that oxidizes combustible gases or vapors from tank farms or liquid unloading, where the combustible gases or vapors being destroyed are routed directly into the burner without energy recovery, and that is not subject to Rule 1118 – Control of Emissions from Refinery Flares or Rule 1149 – Storage Tank and Pipeline Cleaning and Degassing.

(18) FLUIDIZED CATALYTIC CRACKING UNIT (FCCU) means a Unit in which petroleum intermediate feedstock is charged and fractured into smaller molecules in the presence of a catalyst; or reacts with a contact material to improve feedstock quality for additional processing; and the catalyst or contact material is regenerated by burning off coke and other deposits. The FCCU includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat including a CO ~~b~~Boiler.

(19) FORMER RECLAIM FACILITY means a Facility, or any of its successors, that was

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

in the NOx Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX, that has received a Final Determination Notification, and is no longer in the NOx RECLAIM program.

(20) FUNCTIONALLY SIMILAR means, for the purpose of this rule, a Unit that will perform the same purpose as a Unit that was decommissioned in an approved B-Cap.

(21) GAS TURBINE means an internal-combustion engine in which the expanding combustion gases drive a turbine which then drives a generator to produce electricity. Gas Turbines can be equipped with a cogeneration gas turbine that recovers heat from the Gas Turbine exhaust and can include a Duct Burner.

(22) HEAT INPUT means the heat of combustion released by burning a fuel source, using the Higher Heating Value of the fuel. This does not include the enthalpy of incoming combustion air.

(23) HIGHER HEATING VALUE (HHV) means the total heat liberated per mass of fuel combusted expressed as British thermal units (Btu) per pound or cubic feet when fuel and dry air at standard conditions undergo complete combustion and all resulting products are brought to their standard states at standard conditions.

(24) HYDROGEN PRODUCTION PLANT means a Facility that produces hydrogen by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes which primarily supplies hydrogen for ~~p~~Petroleum ~~r~~Refineries and Facilities with Related Operations to Petroleum Refineries.

(25) IMPLEMENTATION COMPLIANCE PLAN (I-PLAN) means an implementation plan for Facilities with six or more Units that includes an ~~alternative~~ implementation schedule and emission reduction targets.

(26) I-PLAN PERCENT REDUCTION TARGET means the percent reduction target ~~specified~~ for each phase of an I-Plan as specified in Table 6.

(27) NATURAL GAS means a mixture of gaseous hydrocarbons, with at least 80 percent methane (by volume), and of pipeline quality, such as the gas sold or distributed by any utility company regulated by the California Public Utilities Commission.

(28) NEW UNIT means, for the purpose of this rule, any Unit that is subject to this rule ~~meets the applicability of subdivision (b)~~ where the South Coast AQMD Permit to Construct is issued on or after [*DATE OF ADOPTION*].

(29) OXIDES OF NITROGEN (NOx) EMISSIONS means the sum of nitric oxide and nitrogen dioxide emitted in the flue gas, calculated, and expressed as nitrogen dioxide.

(30) PARTS PER MILLION BY VOLUME (ppmv) means, for the purpose of this rule, milligram of pollutant per liter of dry combustion exhaust gas at standard conditions.

(31) PETROLEUM COKE CALCINER means a Unit used to drive off contaminants from

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

green petroleum coke by bringing the coke into contact with heated gas for the purpose of thermal processing. The Petroleum Coke Calciner includes, but is not limited to, a kiln, which is a refractory lined cylindrical device that rotates on its own axis, and a pyroscrubber, which combusts large carbon particles in a stream of waste gas.

(32) PETROLEUM COKE CALCINING FACILITY means a ~~Unit within a~~ Petroleum Refinery, or ~~as~~ a separate Facility, that operates a ~~p~~Petroleum ~~c~~Coke ~~c~~Calciner.

(33) PETROLEUM REFINERY means a Facility identified by the North American Industry Classification System Code 324110, Petroleum Refineries.

(34) ~~PHASE I, PHASE III, OR PHASE III~~ BARCT B-CAP ANNUAL EMISSIONS means the total Facility NOx mass emissions remaining based on ~~per Facility that incorporates BARCT~~ Alternative BARCT NOx Limits for Phase I, Phase II, and if applicable Phase III, decommissioned ~~unit~~Units, and other emission reduction strategies to meet the respective Phase I, Phase II, or if applicable Phase III Facility BARCT Emission Targets in an I-Plan and are calculated pursuant to Attachment B of this rule.

(35) ~~PHASE I, PHASE II, OR PHASE III~~ BARCT EQUIVALENT MASS EMISSIONS means the Facility total NOx mass emissions remaining based on ~~per Facility that incorporates respective BARCT~~ Alternative BARCT NOx Limits for Phase I, Phase II, and if applicable Phase III in an approved B-Plan that are designed to meet the respective Phase I, Phase II, or if applicable Phase III Facility BARCT Emission Targets in an I-Plan and are calculated pursuant to Attachment B of this rule.

(36) ~~PHASE I, PHASE II, OR PHASE III~~ FACILITY BARCT EMISSION TARGET means the total Facility NOx mass emissions ~~per Facility~~ that must be achieved in an approved B-Plan or B-Cap ~~that are~~ based on the percent reduction target of Phase I, Phase II, or if applicable, Phase III of an I-Plan ~~option in Table 6~~ and are calculated pursuant to Attachment B of this rule.

(37) PROCESS HEATER means any Unit fired with gaseous and/or liquid fuels which transfers heat from combusted gases to water or process streams.

(38) RATED HEAT INPUT CAPACITY means the maximum heat input capacity, which is the total heat of combustion released by burning a fuel source, as specified by the South Coast AQMD permit.

(39) REPRESENTATIVE NOx CONCENTRATION means the most representative NOx emissions in the exhaust of the Unit ~~as approved by the Executive Officer and~~ measured by a certified CEMS if the Unit operates with a certified CEMS or the most recent approved source test for ~~u~~Units not operating a certified CEMS. The

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

Representative NOx Concentration for ~~u~~Units that do not have CEMS or source test emission data will be based on the South Coast AQMD Annual Emission Report default emission factor for th~~at~~ose Units.

(40) RULE 1109.1 EMISSION LIMITS mean the NOx and CO emission limits and corresponding percent O_2 correction listed in paragraphs (d)(3), (d)(4), Table 1, Table 2, Table 4, Table 5, an approved B-Plan, or an approved B-Cap.

(41) STANDARD CONDITIONS for a Former RECLAIM Facility is as defined by Rule 102 – Definition of Terms.

(42) STEAM METHANE REFORMER (SMR) HEATER means any Unit that is fired with gaseous fuels and transfers heat from the combusted fuel to process tubes that contain catalyst, which converts light hydrocarbons combined with steam to hydrogen.

(43) SULFURIC ACID FURNACE means a Unit fueled with gaseous fuels and/or hydrogen sulfide gas used to convert elemental sulfur and/or decompose spent sulfuric acid, into sulfur dioxide (SO_2) gas.

(44) SULFURIC ACID PLANT means a Unit within a Petroleum Refinery, or ~~as~~ a separate Facility, engaged in the production of commercial grades of sulfuric acid, or regeneration of spent sulfuric acid into commercial grades of sulfuric acid.

(45) SULFUR RECOVERY PLANT means a Unit within a Petroleum Refinery, or ~~as~~ a separate Facility, that recovers elemental sulfur or sulfur compounds from sour or acid gases and/or sour water generated by Petroleum Refineries.

(46) SULFUR RECOVERY UNITS/TAIL GAS (SRU/TG) INCINERATORS means the thermal or catalytic oxidizer where the residual hydrogen sulfide in the gas exiting the ~~s~~Sulfur ~~r~~Recovery ~~p~~Plant (tail gas) is oxidized to SO_2 before being emitted to the atmosphere.

(47) UNIT means, for the purpose of this rule, any ~~b~~Boilers, ~~f~~Flares, FCCUs, ~~g~~Gas ~~t~~Turbines, ~~p~~Petroleum ~~c~~Coke ~~c~~Calciners, ~~p~~Process ~~h~~Heaters, SMR ~~heaters~~Heaters, ~~s~~Sulfuric ~~a~~Acid ~~f~~Furnaces, SRU/TG ~~incinerators~~Incinerators, or ~~v~~Vapor ~~i~~Incinerators requiring a South Coast AQMD permit and not required to comply with a ~~another~~ NOx emission limit in another South Coast AQMD Regulation XI rule.

(48) UNIT REDUCTION means the potential NOx emission reduction for a Unit if the Unit's NOx emissions were reduced from the Representative NOx Concentration to the applicable NOx concentration limit in Table 1 based on the Baseline Emissions calculated pursuant to Attachment B of this rule.

Commented [A2]: "Baseline Emissions" is not defined.

(49) UNITS WITH COMBINED STACKS means two or more Units where the flue gas from the~~se~~ Units are combined in one or more common stack(s).

(50) VAPOR INCINERATOR means a thermal oxidizer, afterburner, or other device for

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

burning and destroying air toxics, volatile organic compounds, or other combustible vapors in gas or aerosol form in gas streams.

(d) Emission Limits

(1) Except as otherwise allowed under this rule, on and after the applicable compliance dates established pursuant to subdivision (g), ~~A~~an owner or operator shall not operate a ~~u~~Unit that results in the discharge of NOx and CO at concentrations in excess of ~~exceeds~~ the applicable ~~NOx and CO~~ emission limits in Table 1, at the percent O_2 correction specified in Table 1, and the averaging time specified in Table 1 or subdivision (k), whichever is applicable. ~~pursuant to the compliance schedule insubdivision (g)~~

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 1: NOx AND CO EMISSION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O2 Correction (%)	Rolling Averaging Time[1]
Boilers <40 MMBtu/hour	Pursuant to paragraph (d)(3)	400	3	24-hour
Boilers ≥40 MMBtu/hour	5	400	3	24-hour
FCCU	2	500	3	365-day
	5			7-day
Flares	20	400	3	2-hour
Gas Turbines fueled with Natural Gas	2	130	15	24-hour
Gas Turbines fueled with Gaseous Fuel other than Natural Gas	3	130	15	24-hour
Petroleum Coke Calciner	5	2,000	3	365-day
	10			7-day
Process Heaters <40 MMBtu/hour	Pursuant to paragraph (d)(4)	400	3	24-hour
Process Heaters ≥40 MMBtu/hour	5	400	3	24-hour
SMR Heaters	5	400	3	24-hour
SMR Heaters with Gas Turbine	5	130	15	24-hour
SRU/TG Incinerators	30	400	3	24-hour
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	30	400	3	24-hour

[1] Averaging times apply to ~~u~~Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for ~~u~~Units without CEMS are specified in subdivision (k).

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(2) Conditional NOx and CO Emission Limits

(A) An owner or operator of a ~~u~~Unit may elect ~~is eligible~~ to meet the NOx and CO emission limits in Table 2~~,~~ in lieu of the NOx and CO emission limits in Table 1 provided:

(i) The Executive Officer has not issued a Permit to Construct with an emission limit at or below the applicable Table 1 NOx emission limit on or after December 4, 2015 for the installation of a post combustion control device for the ~~u~~Unit;

(ii) For a ~~p~~Process ~~h~~Heater with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour and less than or equal to 110 MMBtu/hour ~~or less~~, the Unit Reduction calculated pursuant to Attachment B of this rule is less than 10 tons per year ~~based the applicable Table 1 NOx emission limit~~;

(iii) For ~~b~~Boilers or ~~p~~Process ~~h~~Heaters with a Rated Heat Input Capacity greater than 110 MMBtu/hour, the Unit Reduction calculated pursuant to Attachment B of this rule is less than 20 tons per year ~~based on the applicable Table 1 NOx emission limit~~;

(iv) The South Coast AQMD Permit to Construct or South Coast AQMD Permit to Operate for the ~~u~~Unit does not have a condition that limits the NOx concentration to a level at or below the applicable Table 1 NOx emission limit;

(v) The Representative NOx Concentration of the ~~u~~Unit is not at or below the applicable Table 1 NOx emission limit; and

(vi) The ~~u~~Unit is not identified as being decommissioned in an approved B-Plan for reductions in an I-Plan~~or approved B- Cap~~ pursuant to subparagraph (e)(1)(D).

~~(B) An owner or operator that meets the conditions in subparagraph (d)(2)(A) that elects to meet the NOx and CO emission limits in Table 2 in lieu of the NOx and CO emission limits in Table 1 shall:~~

~~(i) Before July 1, 2022, submit a complete South Coast AQMD permit application to apply for a permit condition that limits the NOx emissions to the applicable levels specified in Table 2; and~~

~~(ii) No later than 18 months after the South Coast AQMD Permit to Construct is issued, meet the NOx and CO emission limits at the percent O_2 correction and the averaging time specified~~

~~(C)~~(B) ~~in Table 2 or subdivision (k), whichever is applicable~~Notwithstanding

Commented [A3]: Relates to Schedule. Moved to section (g).

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

subparagraphs (d)(2)(A) ~~and (d)(2)(B), an owner or operator shall meet~~the Conditional NOx and CO Emission Limits in Table 2 apply to a Unit in lieu of the NOx and CO Emission Limits in Table 1 if:

(i) The owner or operator of the Unit is submitting a B-Plan ~~or a B-Cap~~, and the~~ir~~ ~~u~~Unit is listed in Table D-1; or

(ii) The owner or operator of the Unit is submitting a B-Cap and has selected I-Plan Option 4, and the~~ir~~ ~~u~~Unit is listed in Table D-2.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 2: CONDITIONAL NOx AND CO EMISSION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers >110 MMBtu/hour	7.5	400	3	24-hour
FCCUs	8	500	3	365-day
	16			7-day
Gas Turbines fueled with Natural Gas	2.5	130	15	24-hour
Process Heaters 40 – 10 MMBtu/hour	18	400	3	24-hour
Process Heaters >110 MMBtu/hour	22	400	3	24-hour
SMR Heaters	7.5	400	3	24-hour
Vapor Incinerators	40	400	3	24-hour

[1] Averaging times apply to ~~u~~Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for ~~u~~Units without CEMS are specified in subdivision (k).

(3) Boilers with Rated Heat Input Capacity Less Than 40 MMBtu/hour

An owner or operator of a ~~b~~Boiler with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity less than 40 MMBtu/hour shall:

(A) ~~Before January 1, 2023, have~~Submit a South Coast AQMD Permit application by no later than January 1, 2023 requesting ~~that includes an enforceable~~ emission limits ~~that does~~ not to exceed 40 ppmv NOx and 400 ppmv CO, at three percent O_2 correction, as demonstrated pursuant to ~~and limits~~ the averaging times specified in ~~to~~ Table 1 or subdivision (k)~~,~~ whichever is applicable.

(B) On and after ~~January 1, 2023~~the date of Permit to Construct/Operate issuance, not operate a ~~b~~Boiler that exceeds 40 ppmv NOx and 400 ppmv CO at three percent O_2 correction as demonstrated pursuant to the averaging times specified in Table 1 or subdivision (k), whichever is applicable; and

(C) No later than six months after an owner or operator cumulatively replaces

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

either 50 percent or more of the burners in a ~~b~~Boiler or replaces burners that represent 50 percent or more of the ~~heat~~ Heat ~~i~~Input in a ~~b~~Boiler, where the cumulative replacement begins on~~from~~ July 1, 2022, shall:

(i) Submit a ~~complete~~ South Coast AQMD permit application requesting emission limits not to exceed ~~to impose a~~ 5 ppmv NOx ~~emission limit~~ and ~~a~~ 400 ppmv CO, ~~emission limit~~ at three percent O_2 correction, as demonstrated pursuant to ~~that limits~~ the averaging times specified in ~~to~~ Table 1 or subdivision (k)~~,~~ whichever is applicable; and

(ii) Meet the emission limits specified in ~~pursuant to~~ clause (d)(3)(C)(i) no later than 36 months after a South Coast AQMD Permit to Construct is issued.

Commented [A4]: Move to Section (g)

(4) Process Heaters with Rated Heat Input Less Than 40 MMBtu/hour

An owner or operator of a ~~p~~Process ~~h~~Heater with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity less than 40 MMBtu/hour and without a certified CEMS shall:

(A) Submit ~~Before January 1, 2023, have~~ a South Coast AQMD Permit application by no later than January 1, 2023 requesting ~~that includes an enforceable~~ emission limits not to exceed ~~that does not exceed~~ 40 ppmv NOx and 400 ppmv CO, at three percent O_2 correction, as demonstrated pursuant to ~~and limits~~ the averaging times ~~to~~ specified in Table 1 or subdivision (k)~~,~~ whichever is applicable;

(B) On and after ~~January 1, 2023~~the date of Permit to Construct/Operate issuance, not operate a ~~p~~Process ~~h~~Heater that exceeds 40 ppmv NOx and 400 ppmv CO, at three percent O_2 correction as demonstrated pursuant to the averaging times specified in Table 1 or subdivision (k)~~,~~ whichever is applicable; and

(C) Effective [*TEN YEARS AFTER DATE OF ADOPTION*], no later than six months after an owner or operator cumulatively replaces either 50 percent or more of the burners in a ~~p~~Process ~~h~~Heater or replaces burners that represent 50 percent or more of the ~~h~~Heat ~~i~~Input in a ~~p~~Process ~~h~~Heater, where the cumulative replacement begins on~~from~~ [*FIVE YEARS AFTER DATE OF ADOPTION*]~~, shall~~:

(i) Submit a ~~complete~~ South Coast AQMD permit application requesting ~~to impose a~~9 ppmv NOx emission limit and a 400 ppmv CO emission limit at three percent O_2 correction and limits the averaging times to those specified in Table 1 or subdivision (k), whichever is applicable; and

(ii) Meet the emission limits specified in ~~pursuant to~~ clause

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(d)(4)(C)(i) no later than 36 months after a South Coast AQMD Permit to Construct is issued.

Commented [A5]: Move to Section (g)

(5) Gas Turbines

Notwithstanding the NOx emission limits in Table 1, an owner or operator shall not operate a ~~g~~Gas ~~t~~Turbine that exceeds 5 ppmv NOx corrected to 15 percent O_2 correction based on a 24-hour rolling average during natural gas curtailment periods, where there is a shortage in the supply of pipeline natural gas due solely to supply limitations or restrictions in distribution pipelines by the utility supplying the gas, and not due to the cost of natural gas, provided:

(A) A daily ~~g~~Gas ~~t~~Turbine operating record is maintained that includes the actual start and stop time, total hours of operation, and type (liquid or gas) and quantity of fuel used; and

(B) This information is available to South Coast AQMD staff upon request for at least five years ~~from the date of entry~~.

(6) An owner or operator of ~~u~~Units with combined stacks shall be subject to the most stringent applicable Table 1 or Table 2 NOx and CO emission limits at the applicable percent O_2 correction based on the averaging times specified in Table 1 or subdivision (k), whichever is applicable.

(7) An owner or operator of a ~~u~~Unit with a CO emission limit in a South Coast AQMD Permit to Operate that was established before [DATE OF ADOPTION], shall meet the CO emission limit in the Emission and Requirements section of the South Coast AQMD Permit to Operate in lieu of the CO emission limit specified in Table 1, ~~or~~ Table 2, or Table 4.

(8) An owner or operator of a ~~u~~Unit subject to ~~with~~ an averaging time less than a 365-day rolling average in Table 1 or Table 2 that operates a CEMS shall be required to demonstrate compliance with the applicable Rule 1109.1 Emission Limits~~NOx emission limits in Table 1, Table 2, an approved B-Plan, or an approved B-Cap~~ six months after~~,~~ either the date the South Coast AQMD Permit to Operate is issued, 36 months after the South Coast AQMD Permit to Construct is issued, or completion of a compliance demonstration source test, whichever is sooner.

Commented [A6]: Move to Section (g)

(9) An owner or operator of a ~~u~~Unit subject to a 365-day rolling average in Table 1 or Table 2 shall demonstrate compliance with the applicable Rule 1109.1 Emission Limits beginning 14 months after either the date the South Coast AQMD Permit to Operate is issued, 36 months after the South Coast AQMD Permit to Construct is issued, or completion of a compliance demonstration source test, whichever is sooner.

Commented [A7]: Move to Section (g)

(e) B-Plan and B-Cap Requirements

(1) An owner or operator of a ~~f~~Facility with six or more ~~u~~Units that elects to meet the NOx emission limits in an approved B-Plan in lieu of meeting the Table 1 or Table

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

2 NOx emission limits shall:

(A) Before July 1, 2022, submit an application for a B-Plan that includes all ~~u~~Units subject to this rule, with the exception of any ~~b~~Boiler or ~~p~~Process ~~h~~Heater less than 40 MMBtu/hour that will meet the NOx emission limits specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option, for review and approval pursuant to subdivision (i);

Commented [A8]: Move to Section (g)

(B) Select an Alternative BARCT NOx Limit for Phase I, Phase II, and if applicable Phase III, for each Unit to meet the respective Phase I, Phase II, and if applicable Phase III BARCT Equivalent Mass Emissions where the Alternative BARCT NOx Limit shall not exceed the applicable conditional NOx emission limit in Table 2 for any Unit that is meeting a conditional NOx emission limit pursuant to subparagraphs (d)(2)(A) and (g)(2)~~:~~;

(i) ~~The Conditional NOx and CO limit in Table 2, for any unit that is meeting a Conditional NOx and CO Emission Limit pursuant to subparagraphs (d)(2)(A) and (d)(2)(B).~~

(C) ~~Comply with a condition in the SCAQMD Permit to Operate that limits the NOx concentration to the Alternative BARCT NOx Limit for Phase I, Phase II, and if applicable Phase III, for each uUnit in the approved B-Plan based on the schedule established in the approved I-Plan; and~~

~~(D) Not include emission reductions for any unit that is permanently decommissioned; and~~

~~(E)~~(D) Not operate a ~~unit~~ Unit in an approved B-Plan that exceeds the Alternative BARCT NOx Limit and applicable~~,~~ CO emission limit, based on the applicable averaging time in Table 1 or ~~the~~ subdivision (k), whichever is applicable, ~~in an approved B-Plan,~~ based on the implementation schedule in an~~the~~ approved I-Plan.

Commented [A9]: Section (C) and (D) are redundant. Delete Section (C)

(2) An owner or operator of a ~~f~~Facility with six or more ~~u~~Units that elects to meet the NOx ~~and CO~~ emission limits in an approved B-Cap in lieu of the NOx emission limits in ~~meeting~~ Table 1 or ~~and~~ Table 2 ~~NOx concentration limits~~ shall:

(A) Before July 1, 2022, submit a B-Cap and an I-Plan that include~~s~~ all ~~u~~Units subject to this rule, with the exception of any ~~b~~Boiler or ~~p~~Process H~~h~~eater with a Rated Heat Input Capacity of less than 40 MMBtu/hour that will meet the NOx emission limit s specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last ~~C~~compliance ~~D~~date in Table 6 for the selected I-Plan option, for review and approval pursuant to subdivision (i);

Commented [A10]: Move to Section (g)

(B) Select an Alternative BARCT NOx Limit for Phase I, Phase II, and if applicable Phase III, for each Unit to meet the respective Phase I, Phase II, and if applicable ~~or~~ Phase III BARCT Equivalent Mass Emissions where

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

the Alternative BARCT NOx Limit shall not exceed~~;~~:

(i) The applicable Maximum Alternative BARCT NOx Limit ~~for the applicable unit,~~ specified in Table 3; and

(ii) The Conditional NOx ~~and CO~~ emission limit in Table 2, for any ~~u~~Unit that is meeting a Conditional NOx ~~and CO~~ ~~E~~emission ~~L~~limit pursuant to subparagraphs (d)(2)(A) and~~or~~ (~~d~~g)(2)~~(B)~~.

(C) Comply with a condition in the South Coast AQMD Permit to Operate that limits the NOx concentration to the Alternative BARCT NOx Limit for Phase I, Phase II, and if applicable Phase III for each ~~unit~~ Unit in the approved B-Cap based on the schedule established in the approved I-Plan;

(D) For any ~~u~~Unit that is permanently decommissioned, represent the decommissioned ~~u~~Unit as Table 1 or Table 2 NOx emissions, as applicable, in the Phase I, Phase II, and if applicable~~or~~ Phase III Facility BARCT Emission Target in an approved B-Cap, and ~~for the unit that is decommissioned the owner or operator shall~~:

(i) Surrender the South Coast AQMD Permit to Operate for the decommissioned Unit no later than the compliance date for Phase I in I-Plan Option 4 and no later than the permit submittal date for all other phases in an approved I-Plan;

(ii) Disconnect and blind the fuel line(s) for the decommissioned Unit on or before the date the Permit to Operate is surrendered pursuant to clause (e)(2)(D)(i); and

(iii) Not sell the ~~unit~~ decommissioned Unit ~~for operation~~ to another entity for operation within the South Coast Air Basin;

(E) Not operate any ~~unit~~ Unit unless the NOx emissions for all ~~units~~ Units in the approved B-Cap are in aggregate at or below the applicable Phase I, Phase II, and if applicable~~or~~ Phase III Facility BARCT Emission Target, based on the schedule in the approved I-Plan; and

(F) Not add a new ~~u~~Unit that will be subject to this rule that increases the ~~f~~Facility emissions above applicable Phase I, Phase II, or Phase III Facility BARCT Emission Target, unless:

(i) All ~~u~~Units in the approved B-Cap meet the BARCT Equivalent Mass Emissions;

(ii) The new ~~u~~Unit is not ~~f~~Functionally ~~s~~Similar to any ~~u~~Unit that was decommissioned in the approved B-Cap; and

(iii) The new ~~u~~Unit will not increase overall ~~f~~Facility throughput.~~; and~~

~~(iv) The total amount of NOx emission reductions from units that were decommissioned, represents 15 percent or less of Final~~

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~Phase Facility BARCT Emission Target in an approved B-Cap.~~

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 3: MAXIMUM ALTERNATIVE BARCT NOX LIMITS FOR A B-CAP

Unit	Maximum Alternative BARCT NOx Limit	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers and Process Heaters <40 MMBtu/hour	40 ppmv	3	24-~~day~~hour
Boilers and Process Heaters ≥40 MMBtu/hour	50 ppmv	3	24-~~day~~hour
FCCUs	8 ppmv	3	365-day
	16 ppm		7-day
Gas Turbines	5 ppmv	15	24-~~day~~hour
Petroleum Coke Calciners	100 tons/year	N/A	365-day
SRU/TG Incinerators	100 ppmv	3	24-~~day~~hour
Vapor Incinerators	40 ppmv	3	24-~~day~~hour

1 Averaging times apply to ~~u~~Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for ~~u~~Units without CEMS are specified in subdivision (k).

(f) Interim Emission Limits

~~(1)~~ An owner or operator of a Former RECLAIM ~~f~~Facility that elects to comply with the emission limits in Table 1, Table 2, or an approved B-Plan shall not operate a ~~u~~Unit that exceeds the applicable interim NOx and CO emission limits in Table 4, based on the measured O_2 correction in Table 4, and the averaging time in Table 4 or

~~(2)~~(1) subdivision (k)~~,~~ whichever is applicable, until that ~~u~~Unit is required to meet another Rule 1109.1 Emission Limit pursuant to the compliance schedule in paragraph (g)(1) or an approved I-Plan.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 4: INTERIM NOx AND CO EMISSION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers and Process Heaters <40 MMBtu/hour	40	400	3	365-day
Boilers and Process Heaters ≥40 MMBtu/hour and Boilers and Process Heaters <40 MMBtu/hr operating a certified CEMS	Pursuant to paragraph (f)(2)	400	3	365-day
Flares	105	400	3	365-day
FCCUs	40	500	3	365-day
Gas Turbines fueled with Natural Gas or Other Gaseous Fuel	20	130	15	365-day
Petroleum Coke Calciners	85	2,000	3	365-day
SMR Heaters	20[2]	400	3	365-day
	60[3]			365-day
SMR Heaters with Gas Turbine	5	130	15	365-day
SRU/TG Incinerators	100	400	3	365-day
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	105	400	3	365-day

[1] Averaging times are applicable to ~~u~~Units with a CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for ~~u~~Units without CEMS are specified in subdivision (k).

[2] SMR Heaters equipped with post-combustion air pollution control equipment that was installed before [*DATE OF ADOPTION*].

[3] SMR Heaters not equipped with post-combustion air pollution control equipment as of [*DATE OF ADOPTION*].

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(2) Interim NOx emission limits for Boilers and Process Heaters ≥40 MMBtu/hour and <40 MMBtu operating a certified CEMS

An owner or operator of a Former RECLAIM Facility that elects to comply with the emission limits in Table 1, Table 2, or an approved B-Plan, shall:

(A) Not exceed the applicable interim NOx emission ~~rate~~ limit in Table 5, calculated pursuant to Attachment A Section (A-2) of this rule, for all ~~b~~Boilers and ~~p~~Process ~~h~~Heaters with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour ~~and boilers and process heaters with a rated heat input capacity less than 40 MMBtu/hour that operate with a NOx CEMS~~.

TABLE 5: INTERIM NOX EMISSION RATES FOR BOILERS AND PROCESS HEATERS ≥40 MMBTU/HOUR and <40 MMBtu/hr operating a certified CEMS

Units	An Owner or Operator that Elects to Comply with an Approved:	Facility NOx Emission Rate (pounds/million Btu)	Rolling Averaging Time
Boilers and Process Heaters: ≥40 MMBtu/Hour and <40 MMBtu/hour |Operating a Certified	B-Plan using I-Plan Option 3	0.02	365-day
	B-Plan	0.03	365-day

(B) Demonstrate compliance with the applicable interim NOx emission ~~rate~~ limit in Table 5 until all ~~b~~Boilers and ~~p~~Process ~~h~~Heaters subject to paragraph (f)(2) meet the NOx concentration limits in Table 1, Table 2, or an approved B-Plan.

(3) An owner or operator of a Former RECLAIM Facility that elects to comply with an approved B-Cap shall not operate any ~~u~~Unit included in the approved B-Cap unless the NOx emissions for all ~~u~~Units in the B-Cap are in aggregate at or below the Baseline Facility Emissions.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(g) Compliance Schedule

(1) An owner or operator of a ~~u~~Unit that elects ~~is required~~ to meet the NOx and CO emission~~concentration~~ limits specified in Table 1 shall:

(A) Before July 1, 2023, submit a ~~complete~~ South Coast AQMD permit application requesting ~~to establish a~~ permit conditions that limits ~~the~~ NOx and CO emissions to the applicable concentrations in Table 1, ~~concentration~~ based on the percent O_2 correction in Table 1, and the averaging time in Table 1 or subdivision (k)~~,~~ whichever is applicable, unless the owner or operator has a South Coast AQMD Permit to Construct or a South Coast AQMD Permit to Operate with ~~the~~ a NOx concentration limit at or below the applicable Table 1 NOx limit with the percent O_2 correction and ~~, based on~~ the averaging time specified in Table 1; and

(B) Not operate a ~~u~~Unit~~,~~ that exceeds the applicable NOx and CO emission limits in Table 1, based on the percent O_2 correction in Table 1, and the averaging time in Table 1 or subdivision (k)~~,~~ whichever is applicable:

(i) ~~No l~~Later than 36 months after a South Coast AQMD Permit to Construct is issued; or

(ii) ~~No l~~Later than July 1, 2023 if a permit application was not required as specified in subparagraph (g)(1)(A).

(2) An owner or operator that meets the conditions in subparagraph (d)(2)(A) that elects to meet the NOx and CO emissions limits in Table 2 in lieu of the NOx and CO emissions limits in Table 1 shall:

(A) Before July 1, 2022, submit a South Coast AQMD permit application requesting permit conditions that limit NOx and CO emissions to the applicable concentrations in Table 2; and

(B) No later than 18 months after the South Coast AQMD Permit to Construct is issued, meet the NOx and CO limits in Table 2, at the percent O_2 correction in Table 2, and averaging time specified in Table 2 or subdivision (k) whichever is applicable.

~~(2)~~(3) I-Plan Requirements

An owner or operator of a Facility with six or more ~~u~~Units that elects to meet the NOx and CO emission limits in Table 1 or Table 2 using an alternative compliance schedule to paragraph (g)(1) or that elects to comply with an approved B-Plan or B-Cap shall:

(A) Before July 1, 2022, submit an I-Plan pursuant to paragraph (i)(1) that includes all ~~u~~Units subject to Table 1 or Table 2 NOx emission limits for review and approval pursuant to paragraph (i)(4), with the exception of

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(g) Compliance Schedule

(1) An owner or operator of a ~~u~~Unit that elects ~~is required~~ to meet the NOx and CO emission~~concentration~~ limits specified in Table 1 shall:

(A) Before July 1, 2023, submit a ~~complete~~ South Coast AQMD permit application requesting ~~to establish a~~ permit conditions that limit~~s~~ ~~the~~ NOx and CO emissions to the applicable concentrations in Table 1, ~~concentration~~ based on the percent O_2 correction in Table 1, and the averaging time in Table 1 or subdivision (k)~~,~~ whichever is applicable, unless the owner or operator has a South Coast AQMD Permit to Construct or a South Coast AQMD Permit to Operate with ~~the~~ a NOx concentration limit at or below the applicable Table 1 NOx limit with the percent O_2 correction and ~~, based on~~ the averaging time specified in Table 1; and

(B) Not operate a ~~u~~Unit~~,~~ that exceeds the applicable NOx and CO emission limits in Table 1, based on the percent O_2 correction in Table 1, and the averaging time in Table 1 or subdivision (k)~~,~~ whichever is applicable:

(i) ~~No l~~Later than 36 months after a South Coast AQMD Permit to Construct is issued; or

(ii) ~~No l~~Later than July 1, 2023 if a permit application was not required as specified in subparagraph (g)(1)(A).

(2) An owner or operator that meets the conditions in subparagraph (d)(2)(A) that elects to meet the NOx and CO emissions limits in Table 2 in lieu of the NOx and CO emissions limits in Table 1 shall:

(A) Before July 1, 2022, submit a South Coast AQMD permit application requesting permit conditions that limit NOx and CO emissions to the applicable concentrations in Table 2; and

(B) No later than 18 months after the South Coast AQMD Permit to Construct is issued, meet the NOx and CO limits in Table 2, at the percent O_2 correction in Table 2, and averaging time specified in Table 2 or subdivision (k) whichever is applicable.

~~(2)~~(3) I-Plan Requirements

An owner or operator of a Facility with six or more ~~u~~Units that elects to meet the NOx and CO emission limits in Table 1 or Table 2 using an alternative compliance schedule to paragraph (g)(1) or that elects to comply with an approved B-Plan or B-Cap shall:

(A) Before July 1, 2022, submit an I-Plan pursuant to paragraph (i)(1) that includes all ~~u~~Units subject to Table 1 or Table 2 NOx emission limits for review and approval pursuant to paragraph (i)(4), with the exception of

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

any ~~b~~Boiler or ~~p~~Process ~~h~~Heater with a Rated Heat Input Capacity less than 40 MMBtu/hour that will meet the NOx emission limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option;

(B) Calculate the Phase I, Phase II, and if applicable~~or~~ Phase III Facility BARCT Emission Targets~~,~~ pursuant to Attachment B of this rule;

~~For a B-Cap, the Phase I, Phase II, and Phase III Facility BARCT Emission Targets shall incorporate a reduction of 10 percent, pursuant to Attachment B of this rule;~~

(C) For a B-Plan, calculate the Phase I, Phase II, and if applicable~~or~~ Phase III BARCT Equivalent Mass Emissions, pursuant to Attachment B of this rule;

(D) For a B-Plan, demonstrate that Phase I, Phase II, and if applicable~~or~~ Phase III, BARCT Equivalent Mass Emissions~~,~~ are equal to or less than the respective Phase I, Phase II, and if applicable~~or~~ Phase III Facility BARCT Emission Target;

(E) For a B-Cap, calculate the Phase I, Phase II, and if applicable~~or~~ Phase III BARCT B-Cap Annual Emissions, pursuant to Attachment B of this rule;

(F) For a B-Cap, demonstrate that Phase I, Phase II, and if applicable~~or~~ Phase III BARCT B-Cap Annual Emissions, are equal to or less than the respective Phase I, Phase II, ~~or~~ and if applicable Phase III Facility BARCT Emission Target;

(G) Based on the schedule in the approved I-Plan, implement emission reduction projects to comply with the emission limits in Table 1 or Table 2 or an approved B-Plan or approved B-Cap, to achieve the Phase I, Phase II, and if applicable~~or~~ Phase III Facility BARCT Emission Target; and

(H) For an owner or operator with an approved B-Cap, demonstrate compliance with the emissions requirements and all other requirements no later than the compliance dates listed in Table 6 for the chosen I-Plan ~~for Phase I in I-Plan Option 4 and no later 54 months from South Coast AQMD Permit Application Submittal Date for all other phases of the selected I- Plan option in Table 6 to meet the Phase I, Phase II, or Phase III Facility BARCT Emission Targets~~.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 6: I-PLAN PERCENT REDUCTION TARGETS AND SCHEDULE[1]

		Phase I	Phase II	Phase III
I-Plan Option 1 for B-Plan Only	Percent Reduction Targets	70	100	N/A
	Permit Application Submittal Date	July 1, 2023	January 1, 2027	N/A
	Compliance Date	No later than 36 months after a South Coast AQMD Permit to Construct is issued		N/A
I-Plan Option 2 for B-Plan Only	Percent Reduction Targets	60	80	100
	Permit Application Submittal Date	July 1, 2023	January 1, 2025	January 1, 2028
	Compliance Date	No later than 36 months after a South Coast AQMD Permit to Construct is issued		
I-Plan Option 3 for B-Plan or B-Cap and as allowed pursuant to paragraph (g)(3)	Percent Reduction Targets	50	100	N/A
	Permit Application Submittal Date	January 1, 2025	January 1, 2029	N/A
	Compliance Date	No later than 36 months after a South Coast AQMD Permit to Construct is issued		N/A
I-Plan Option 4 for B-Cap Only	Percent Reduction Targets	50 to 60 (Still in development)	80	100
	Permit Application Submittal Date	N/A	January 1, 2025	January 1, 2028
	Compliance Date	January 1, 2024	No later than 36 months after a South Coast AQMD Permit to Construct is issued	
I-Plan Option 5 for B-Cap Only	Percent Reduction Targets	50	70	100
	Permit Application Submittal Date	July 1, 2022	July 1, 2024	January 1, 2028
	Compliance Date	No later than 36 months after a South Coast AQMD Permit to Construct is issued		

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(3)~~(4) I-Plan Option 3 is only available to an owner or operator of a ~~f~~Facility achieving a NOx emission rate of less than 0.02 pound per million BTU of ~~h~~Heat ~~i~~Input, based on annual emissions for the applicable ~~u~~Units as reported in the 2021 Annual Emissions Report and calculated pursuant to Attachment A, for all the ~~b~~Boilers and ~~p~~Process ~~h~~Heaters with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour based on the maximum rated capacity by [*DATE OF ADOPTION*]; for ~~u~~Units firing at less than the maximum rated capacity, mass emissions shall be less than or equal to the quantity that would occur at maximum rated capacity.

~~(4)~~(5) An owner or operator of a ~~u~~Unit complying with Table 2 conditional emission limits that replaces existing NOx control equipment shall:

(A) Within six months of replacing the existing NOx control equipment, be subject to the applicable Table 1 emission limit;

(B) Apply for a South Coast AQMD permit condition to limit the NOx and CO concentration to the applicable Table 1 emission limit, at the corresponding percent O_2 correction, and averaging times in Table 1 or subdivision (k)~~,~~ whichever is applicable. Replacement of existing NOx control equipment will be determined as:

(i) Existing post-combustion air pollution control equipment for an FCCU, ~~g~~Gas ~~t~~Turbine fueled with natural gas, ~~p~~Process ~~h~~Heater with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour, or SMR Heater is replaced such that the fixed capital cost of the new components for the post- combustion air pollution control equipment exceeds 50 percent of the fixed capital cost that would be required to construct and install a comparable new ~~u~~Unit; or

(ii) 50 percent or more of the burners in a ~~v~~Vapor ~~i~~Incinerator, or 50 percent or more of the ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity of the burners in a ~~v~~Vapor ~~i~~Incinerator, are cumulatively replaced after [*DATE OF ADOPTION*].

~~(5)~~(6) An owner or operator of ~~u~~Unit complying with clauses (d)(2)(B)(i); (d)(3)(C)(i); (d)(4)(C)(i); or subparagraphs (g)(1)(A) or (g)(5)(A) that fails to submit a ~~complete~~ South Coast AQMD permit application by the date specified in clauses (d)(2)(B)(i); (d)(3)(C)(i); (d)(4)(C)(i); or subparagraphs (g)(1)(A) or (g)(5)(A), shall meet the applicable Rule 1109.1 Emission Limits no later than 36 months after the South Coast AQMD permit application submittal date pursuant to clauses (d)(2)(B)(i), (d)(3)(C)(i), or (d)(4)(C)(i), or subparagraphs (g)(1)(A) or (g)(5)(A).

~~(6)~~(7) An owner or operator of a ~~u~~Unit exempt from the Table 1 NOx and CO emission

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

limits pursuant to paragraphs (n)(2), (n)(3), (n)(6), (n)(7), (n)(8) or (n)(9) that exceeds the applicable exemptions limitations shall:

(A) Within six months of the exceedance, submit a ~~complete~~ South Coast AQMD permit application to comply with the corresponding Table 1 emission limits; and

(B) Meet the emission limits specified on Table 1 no later than 36 months after a South Coast AQMD Permit to Construct is issued.

(h) Time Extensions

(1) An owner or operator of a ~~u~~Unit may request one 12--month extension for each ~~u~~Unit from the compliance date in paragraph (g)(1) or the Compliance Date in Table 6 provided:

(A) The South Coast AQMD permit application for the ~~u~~Unit was submitted on or before the date specified in paragraph (g)(1) or the approved I-Plan; and

(B) There are specific circumstances outside of the control of the owner or operator that necessitate an extension of time.

(2) An owner or operator of a ~~u~~Unit with an approved I-Plan may request a time extension from the Compliance Date in Table 6 for a ~~u~~Unit provided:

(A) The South Coast AQMD permit application for the ~~u~~Unit was submitted on or before the date specified in the approved I-Plan;

(B) The month and year for the ~~u~~Unit's scheduled turnaround and the month and year for the ~~u~~Unit's subsequent turnaround is submitted in writing at the time of South Coast AQMD permit application submittal; and

(C) One or more of the following occurred:

(i) The South Coast AQMD Permit to Construct for the ~~unit~~ Unit was issued after the scheduled turnaround date or the South Coast AQMD Permit to Construct for the ~~u~~Unit was issued more than 24 months after the South Coast AQMD permit application was submitted, and either:

(ii) The subsequent scheduled turnaround for the ~~u~~Unit will not occur until 12 months after the Compliance Date in the approved I-Plan; or

(iii) The subsequent scheduled turnaround for the ~~u~~Unit will occur more than 48 months after the South Coast AQMD Permit to Construct was issued.

(3) An owner or operator that requests a time extension pursuant to paragraphs (h)(1) or (h)(2) shall submit the request in writing to the Executive Officer no later than 90 days prior to the Compliance Date in paragraph (g)(1) or the approved I-Plan for the ~~u~~Unit. The time extension request shall include:

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(A) The phase and ~~u~~Unit needing a time extension;

(B) The date the South Coast AQMD permit application was submitted;

(C) The additional time needed to complete the emission reduction project;

(D) Specify if the time extension request is for paragraph (h)(1) or (h)(2);

(E) For time extension requests for paragraph (h)(2), provide the month and year of the scheduled turnaround, and the subsequent turnaround, if applicable, for the ~~u~~Unit; and

(F) The reason(s) a time extension is requested.

(4) The Executive Officer will review the request for the time extension and act on the request within 60 days of receipt provided an owner or operator:

(A) Meets the requirements of paragraph (h)(1) or (h)(2), as applicable;

(B) Submitted the written request within the timeframe and includes the applicable information specified in paragraphs (h)(1) and (h)(2); and

(C) For a time extension request pursuant to paragraphs (h)(1) and (h)(2), the owner or operator shall at a minimum:

(i) For delays due to missed milestones, provide information on schedules and/or construction plans documenting the key milestones and which key milestone(s) were delayed with an explanation actions the operator took to ensure milestones were met and why the delay necessitates additional time;

(ii) For delays related to other agency approvals, provide information to substantiate that the submittal of information to the agency was timely, and the date requested for ~~when~~ application ~~was the~~ approval ~~was requested, and documentation from the agency of reason for the delay~~;

(iii) For delays related to the delivery of parts or equipment, provide purchase orders, invoices, and communications from vendors that demonstrate that equipment was ordered in a timely fashion and delays are outside of the control of the operator; and

(iv) For delays related to contract workers, source testers, installers, or other services, provide an explanation of the service, when the service was requested, the response time, and information to substantiate why the delay necessitates additional time.

(D) For a time extension request allowed under paragraphs (h)(2), the owner or operator shall provide documentation to substantiate that one of the provisions under subparagraph (h)(2)(C) have been met.

(5) If the Executive Officer requests additional information to substantiate the time extension request, the owner or operator shall provide that information within the timeframe specified by the Executive Officer.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(6) If the Executive Officer notifies the owner or operator of approval of a time extension request, the owner or operator shall meet the emission limits in Table 1, an approved B-Plan, or an approved B-Cap within timeframe in the approval, and the approval represents an amendment to the I-Plan.

(7) If the Executive Officer notifies the owner or operator of a disapproval of a time extension request, the owner or operator shall meet the emission limits in Table 1, an approved B-Plan, or an approved B-Cap within 60 calendar days after receiving notification of disapproval of the time extension request or pursuant to the compliance schedule in paragraph (g)(1) or the schedule in an approved I-Plan.

(i) I-Plan, B-Plan, and B-Cap Submittal and Approval Requirements

(1) I-Plan Submittal Requirements

An owner or operator that elects to implement an I-Plan pursuant to paragraph (g)(2) to meet the Alternative BARCT NOx Limits in an approved B-Plan or approved B-Cap shall submit an I-Plan to the Executive Officer for review and approval that:

(A) Identifies each ~~u~~Unit subject to th~~is~~e rule by device identification number with a description of each ~~u~~Unit, with the exception of any ~~b~~Boiler or ~~p~~Process ~~h~~Heater less than 40 MMBtu/hour that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option;

(B) ~~For facilities to use the time extension pursuant to paragraph (h)(2), i~~Identifies the anticipated start and end date (month and year) of the turnaround schedule for each ~~unit~~Unit;

(C) Specifies either I-Plan Option 1 (for a B-Plan only), I-Plan Option 2 (for a B-Plan only)~~-2~~, I-Plan Option 3 (for a B-Plan or B-Cap), I-Plan Option 4 (for a B-Cap only), or I-Plan Option 5 (for a B-Cap only) in Table 6;

(D) Calculates the Phase I, Phase II, ~~or~~ and if applicable Phase III, Facility BARCT Emission Target, pursuant to Attachment B of this rule;

(E) For a B-Plan, identifies each ~~u~~Unit that meets the requirements in ~~under~~subparagraph (d)(2)(A) to qualify for use of a conditional NOx emission limit in Table 2 and verifies the owner or operator submitted a ~~complete~~ South Coast AQMD permit application pursuant to clause (~~d~~g)(2)~~(B)(i)~~;

(F) For the selected I-Plan option specified pursuant to subparagraph (i)(1)(B), calculates the Phase I, Phase II, ~~or~~ and if applicable Phase III, Facility BARCT Emission Target~~,~~ pursuant to Attachment B of this rule; and

(G) Identifies each ~~unit~~Unit by device identification number with a description of each ~~unit~~Unit, that cumulatively meets Phase I, Phase II, and if applicable~~or~~ Phase III Facility BARCT Emission Target.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(2) B-Plan Submittal Requirements

An owner or operator that elects to meet Alternative BARCT NOx Limits in an approved B-Plan pursuant to paragraph (e)(1), shall submit a B-Plan to the Executive Officer for review that:

(A) Identifies for each ~~unit~~Unit subject to th~~is~~ise rule by device identification number with a description of each ~~unit~~Unit, with the exception of any ~~b~~Boiler or ~~p~~Process ~~h~~Heater less than 40 MMBtu/hour that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option;

(B) Specifies the Alternative BARCT NOx Limit for Phase I, Phase II, and if applicable Phase III, of the approved I-Plan;

(C) Calculates the Phase I, Phase II, ~~or~~ and if applicable Phase III, BARCT Equivalent Mass Emissions using the Alternative BARCT NOx Limits identified in subparagraph (g)(2)(B), as calculated pursuant to Attachment B of this rule; and

(D) Demonstrates that Phase I, Phase II, and if applicable ~~or~~ Phase III, BARCT Equivalent Mass Emissions are less than the respective Phase I, Phase II, and if applicable ~~or~~ Phase III Facility BARCT Emission Target.

(3) B-Cap Submittal Requirements

An owner or operator that elects to meet the Alternative BARCT NOx Limits in an approved B-Cap pursuant to paragraph (e)(2), shall submit a B-Cap to the Executive Officer for review that:

(A) Identifies each ~~unit~~Unit subject to th~~is~~ise rule by the device identification number with a description of the ~~unit~~Unit, with the exception of any ~~b~~Boiler or ~~p~~Process ~~h~~Heater less than 40 MMBtu/hour that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option, and:

(B) Specifies the Alternative BARCT NOx Limit that is at or below Maximum Alternative BARCT NOx Limit in Table 3;

(C) Identifies any ~~unit~~Unit that will be decommissioned for each phase of the approved I-Plan;

(D) Identifies any ~~unit~~Unit that will have a reduction in throughput for each phase of the approved I-Plan;

(E) Calculates the Phase I, Phase II, and if applicable~~or~~ Phase III, BARCT Equivalent Mass Emissions using the emission reduction strategies identified in subparagraph (g)(3)(B),~~;~~ as calculated pursuant to Attachment B of this rule; and

(F) Demonstrates that Phase I, Phase II, and if applicable ~~or~~ Phase III, BARCT

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

B-Cap Annual Emissions, are less than the respective Phase I, Phase II, and if applicable ~~or~~ Phase III Facility BARCT Emission Target ~~that incorporates a 10 percent reduction pursuant to subparagraph (g)(2)(C);~~.

(4) I-Plan, B-Plan, and B-Cap Review and Approval Process

(A) The Executive Officer will notify the owner or operator in writing whether the I-Plan, B-Plan, or B-Cap is approved or disapproved. An I-Plan, B-Plan, or B-Cap will be approved provided it meets ~~based on~~ the following criteria:

(i) The I-Plan contains information required in paragraph (i)(1), the B-Plan contains information required in paragraph (i)(2), and the B-Cap contains information required in paragraph (i)(3);

(ii) The owner or operator demonstrates that the requirements of subparagraphs (d)(2)(A) and (~~d~~g)(2)~~(B)~~ have been met for any ~~unit~~Unit that is meeting a Table 2 conditional NOx emission limit~~,~~ in lieu of a Table 1 NOx emission limit, and is not listed in Table D-1 or Table D-2;

(iii) For a B-Plan, the Phase I, Phase II, and if applicable~~or~~ Phase III, Equivalent BARCT Emissions are less than or equal to the respective Phase I, Phase II, and if applicable~~or~~ Phase III, Facility BARCT Emission Target as required in subparagraph (g)(2)(B);

(iv) For a B-Cap, the Phase I, Phase II, ~~or~~ and if applicable Phase III, BARCT B-Cap Annual Emissions are less than or equal to the respective Phase I, Phase II, and if applicable ~~or~~ Phase III, Facility BARCT Emission Target ~~that incorporates a 10 percent reductions pursuant to subparagraph (g)(2)(C)~~;

(v) For a B-Cap, the NOx concentration limit for any ~~unit~~Unit does not exceed the applicable Maximum Alternative BARCT NOx Limits in Table 3.

(B) Within 30 days of receiving written notification from Executive Officer that the I-Plan, B-Plan, or B-Cap is disapproved, the owner or operator shall correct any deficiencies and re-submit the I-Plan, B-Plan, or B-Cap.

(C) Upon receiving written notification from the Executive Officer that the I-Plan, B-Plan, or B-Cap re-submitted pursuant to subparagraph (i)(4)(B) is disapproved, the owner or operator shall comply with the compliance schedule pursuant to paragraph (g)(1).

(5) Modifications to an Approved I-Plan, an Approved B-Plan, and an Approved B-Cap

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(A) An owner or operator that seeks approval to modify an approved I-Plan, an approved B-Plan, or an approved B-Cap shall submit a request in writing to the Executive Officer to modify an Approved I-Plan, an Approved B-Plan, and an Approved B-Cap.

(B) The modification request submitted pursuant to subparagraph (i)(5)(A) shall include all the plan submittal requirements pursuant to paragraph (i)(1) for an approved I-Plan, paragraph (i)(2) for a modification of an approved B-Plan, or paragraph (i)(3) for a modification of an approved B-Plan;

(C) An owner or operator shall modify an approved I-Plan, B-Plan, or B-Cap if:

(i) A ~~unit~~Unit identified as qualifying for the NOx emissions limits in ~~meeting~~ Table 2 no longer meets the requirements of subparagraph (d)(2)(A) or (~~d~~g)(2)~~(B)~~;

(ii) A ~~unit~~Unit in an approved B-Cap or B-Plan, identified as qualifying for the NOx emission limits in ~~meeting~~ Table 2 for purposes of establishing the Phase I, Phase II, or Phase III BARCT Facility Emission Target, is decommissioned;

(iii) A higher Alternative BARCT NOx Limit will be proposed in the South Coast AQMD permit application than the Alternative BARCT NOx Limit selected for that ~~unit~~Unit in the currently approved I-Plan, B-Plan, or B-Cap;

(iv) Any emission reduction project is moved to a later implementation phase, any emission reduction project is moved between phases, or any emission reduction project is removed from a phase; or

(v) The owner or operator receives written notification from the Executive Officer that modifications to the I-Plan, B-Plan, or B-Cap are needed.

(D) Review and approval of any modifications to an I-Plan, B-Plan, or B-Cap shall be conducted in accordance with the review and approval process pursuant to paragraph (i)(4).

(6) Notification of Pending Approval of an I-Plan, B-Plan, or B-Cap

The Executive Officer will make the proposed I-Plan, B-Plan, or B-Cap or proposed modifications to an approved I-Plan, B-Plan, or B-Cap available to the public on the South Coast AQMD website 30 days prior to approval.

(7) Plan Fees

The review and approval of an I-Plan, B-Plan, and B-Cap, or review and approval of a modification of an approved I-Plan, B-Plan, and B-Cap shall be subject to applicable plan fees as specified in Rule 306 – Plan Fees.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(j) CEMS Requirements

(1) An owner or operator of a Former RECLAIM Facility with a ~~unit~~Unit with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity of greater than or equal to 40 MMBtu/hour shall install, certify, operate, and maintain a CEMS to measure NOx and O_2 pursuant to the applicable Rule 218.2 and Rule 218.3 requirements to demonstrate compliance with NOx emission limits at the corresponding percent O_2 correction and averaging times.

(2) An owner or operator of a Former RECLAIM Facility with a ~~s~~Sulfuric ~~a~~Acid ~~f~~Furnace subject to the emission limits in Table 1, Table 4, an approved B-Plan or an approved B-Cap shall:

(i) Install, certify, operate, and maintain a CEMS to measure NOx pursuant to the applicable Rules 218.2 and 218.3 requirements to demonstrate compliance with the Rule 1109.1 Emissions Limits; and

(ii) Within 12 months from [*DATE OF ADOPTION*] shall install, certify, operate, and maintain a CEMS that complies with ~~the~~ Rules 218.2 and 218.3 requirements to measure O_2 and demonstrate compliance with the Rule 1109.1 Emission Limits at the corresponding percent O_2 correction.

(3) An owner or operator of a Former RECLAIM Facility with a ~~unit~~Unit with a CEMS that measures CO at [*DATE OF ADOPTION*] must operate and maintain the CO CEMS pursuant to the applicable Rules 218.2 and 218.3 requirements to demonstrate compliance with the Table 1, Table 2, or Table 3 CO emissions limits and certify the CEMS within 12 months of [*DATE OF ADOPTION*] pursuant to the applicable Rules 218.2 and 218.3 requirements.

(4) An owner or operator of a Former RECLAIM Facility with ~~for~~ a ~~unit~~Unit with a CEMS shall exclude invalid CEMS data pursuant to Rule 218.2 – Continuous Emission Monitoring System: General Provisions and Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications.

(5) Missing Data Procedures for a Facility Complying with a B-Cap

An owner or operator of a ~~unit~~Unit with an approved B-Cap with a non-operational CEMS that is not collecting data, shall:

(A) Calculate missing data using the average of the recorded emissions for the hour immediately before the missing data period and the hour immediately after the missing data period, if the missing data period is less than or equal to 8 continuous hours; or

(B) Calculate missing data using the maximum hourly emissions recorded for the previous 30 days, commencing on the day immediately prior to the day the missing data occurred, if the missing data period is more than 8 continuous hours.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(k) Source Test Requirements

(1) An owner or operator of a ~~unit~~Unit that is not required to install and operate a CEMS pursuant to subdivision (i) shall be required to conduct a source test, with a duration of at least 15 minutes but no longer than two hours, to demonstrate compliance with Rule 1109.1 Emission Limits pursuant to the source test schedule in either Table 7 or Table 8.

(2) Source Test Schedule for Units without Ammonia Emissions in the Exhaust An owner or operator of a ~~u~~Unit that is not required to install and operate a CEMS pursuant to subdivision (i) and does not vent to post-combustion air pollution control equipment with ammonia injection, shall demonstrate compliance with the applicable Rule 1109.1 Emission Limits by conducting source tests according to the schedule in Table 7.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 7: SOURCE TESTING SCHEDULE
FOR UNITS WITHOUT AMMONIA EMISSIONS IN THE EXHAUST

Combustion Equipment	Source Test Schedule
Vapor Incinerators less than 40MMBtu/hr, Flares	• Conduct source test simultaneously for NOx and CO within 36 months from previous source test and every 36 months thereafter
All Other Units	
Units Operating without NOx or CO CEMS	• Conduct source test simultaneously for NOx and CO within 12 months of being subject to Rule 1109.1 Emission Limit and ~~quarterly~~ annually thereafter • ~~Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit if four consecutive quarterly source tests demonstrate compliance with the NOx and CO emission limits~~ • ~~If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the NOx and CO emission limits prior to resuming annual source tests~~
Units operating with NOx CEMS and without CO CEMS	• Conduct source test for CO within 12 months from previous source test and every 12 months thereafter
Units operating without NOx CEMS and with CO CEMS	• Conduct source test for NOx during the first 12 months of being subject to Rule 1109.1 Emission Limit and ~~quarterly~~ annually thereafter • ~~Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit if four consecutive quarterly source tests demonstrate compliance with the NOx and CO emission limits~~ • ~~If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the NOx emissions limits prior to resuming annual source tests~~

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(3) ~~Source Test Schedule for Units with Ammonia Emissions in the Exhaust An owner or operator of a unit with post-combustion air pollution control equipment that requires ammonia injection shall demonstrate compliance with the applicable Rule 1109.1 Emission Limit and ammonia South Coast AQMD permit limit by conducting a source test according to the schedule in Table 8.~~

~~TABLE 8: SOURCE TESTING SCHEDULE FOR UNITS WITH AMMONIA EMISSIONS IN THE EXHAUST~~

~~Combustion Equipment~~	~~Source Test Schedule~~
~~Units operating without NOx, CO, or ammonia CEMS~~	• ~~Conduct source test simultaneously for NOx, CO, and ammonia quarterly during the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit and quarterly thereafter~~ • ~~Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit if four consecutive quarterly source tests demonstrate compliance with the CO, NOx, and ammonia emission limit~~ • ~~If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the NOx, CO, and ammonia emissions limits prior to resuming annual source Tests~~
~~Units operating with NOx CEMS and without CO and ammonia CEMS~~	• ~~Conduct source test for CO and ammonia quarterly during the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit and quarterly thereafter~~ • ~~Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit if four consecutive quarterly source tests demonstrate compliance with the CO and ammonia emission limit~~ • ~~If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the CO and ammonia emissions limits prior to resuming annual source Tests~~

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~Combustion Equipment~~	~~Source Test Schedule~~
~~Units operating with NOx and CO CEMS and without ammonia CEMS~~	• ~~Conduct source test for ammonia quarterly during the first 12 months of being subject to an ammonia South Coast AQMD permit limit and quarterly thereafter~~ • ~~Source tests may be conducted annually after the first 12 months of being subject to an ammonia South Coast AQMD permit limit if four consecutive quarterly source tests demonstrate compliance with the ammonia emission limit~~ • ~~If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the ammonia emissions limits prior to resuming annual source tests~~
~~Units operating with NOx and ammonia CEMS and without CO CEMS~~	• ~~Conduct source test for CO within 12 months from previous source test and every 12 months thereafter~~
~~Units operating with ammonia CEMS and without NOx or CO CEMS~~	• ~~Conduct source tests to determine compliance with NOx and CO emission limits pursuant to Table 7~~

(4) An owner or operator that elects to install and operate a CEMS to demonstrate compliance with the applicable Rule 1109.1 Emission Limits or ammonia South Coast AQMD permit limit at the corresponding percent O_2 correction shall meet the CEMS requirements under subdivision (j).

(5) An owner or operator of with a ~~u~~Unit subject to a Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit, that is not required to install and operate a CEMS pursuant to subdivision (i) and has not conducted a source test within the schedule in Table 7 or Table 8, shall conduct a source test within:

(A) Six months from being subject to the Rule 1109.1 Emission Limit for ~~unit~~Units with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 20 MMBtu/hour.

(B) 12 months from being subject to the Rule 1109.1 Emission Limit for ~~unit~~Units with a R~~r~~ated ~~h~~Heat ~~i~~Input ~~c~~Capacity less than 20 MMBtu/hour.

(6) An owner or operator of a new or modified unitUnit shall conduct the initial source tests within six months from commencing operation.

(7) An owner or operator of a ~~unit~~Unit required to conduct a source test pursuant to

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

subdivision (k) shall:

(A) For ~~unit~~Units that receive a South Coast AQMD Permit to Construct to comply with a Rule 1109.1 Emission Limit, submit a source test protocol, that includes an averaging time of at least 2 hours, for approval within 60 days after the Permit to Construct was issued unless otherwise approved by the Executive Officer;

(B) For ~~unit~~Units that receive a South Coast AQMD permit condition that limits NOx or CO to a Rule 1109.1 Emission Limit, submit a source test protocol, that includes an averaging time of at least 2 hours, for approval within 60 days after being subject to a Rule 1109.1 Emission limit, unless otherwise approved by the Executive Officer, and

(C) Conduct the source test within 90 days after a written approval of the source test protocol by the Executive Officer is distributed.

(8) At least one week prior to conducting a source test, an owner or operator of a ~~unit~~Unit shall notify the Executive Officer by calling 1-800-CUT-SMOG of the intent to conduct source testing and shall provide:

(A) Facility name and identification number;

(B) Device identification number; and

(C) Date when source test will be conducted.

(9) Unless requested by the Executive Officer, after the approval of the initial source test protocol pursuant to paragraph (k)(7), an owner or operator is not required to resubmit a source test protocol for approval pursuant to paragraph (k)(7) if:

(A) The method of operation of the ~~unit~~Unit has not been altered in a manner that requires a South Coast AQMD permit application submittal;

(B) Rule or South Coast AQMD permit emission limits have not become more stringent since the previous source test;

(C) There have been no changes in the source test method that is referenced in the approved source test protocol; and

(D) The approved source test protocol is representative of the operation and configuration of the ~~unit~~Unit.

(10) An owner or operator of a ~~unit~~Unit shall conduct the source test using a South Coast AQMD approved contractor under the Laboratory Approval Program:

(A) Using a South Coast AQMD approved source test protocol;

(B) Using at least one of the following test methods:

(i) South Coast AQMD Source Test Method 100.1 – Instrumental Analyzer Procedures for Continuous Gaseous Emission Sampling; or

(ii) South Coast AQMD Source Test Method 7.1 – Determination of Nitrogen Oxide Emissions from Stationary Sources and South

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

Coast AQMD Source Test Method 10.1 – Carbon Monoxide and Carbon Dioxide by Gas Chromatograph/Non-Dispersive Infrared Detector – Oxygen by Gas Chromatograph-Thermal Conductivity (GC/TCD);

(iii) South Coast AQMD Source Test Method 207.1 for Determination of Ammonia Emissions from Stationary Sources; or

(iv) Any other test method determined to be equivalent and approved by the Executive Officer, and either the California Air Resources Board or the U. S. Environmental Protection Agency, as applicable.

(C) During operation other than startup and shutdown; and

(D) In as-found operating condition.

(11) An owner or operator of a ~~unit~~Unit shall submit all source test reports, including the source test results and a description of the ~~unit~~Unit tested, to the Executive Officer within 60 days of completion of the source test.

(12) Emissions determined to exceed any limits established by this rule by any of the reference test methods in subparagraph (k)(9)(B) shall constitute a violation of the rule.

(13) An owner or operator of a ~~unit~~Unit that exceeds any limits established by this rule by any of the reference test methods in subparagraph (k)(9)(B) shall inform the Executive Officer within 72 hours from the time an owner or operator knew of excess emissions, or reasonably should have known.

(l) Diagnostic Emission Checks

(1) An owner or operator of a ~~unit~~Unit required to perform a source test every 36 months pursuant to subdivision (k) shall:

(A) Perform diagnostic emissions checks of NOx, CO, and O_2 emissions, with a portable NOx, CO, and O_2 analyzer that is calibrated, maintained and operated in accordance with manufacturers specifications and recommendations of the South Coast AQMD Combustion Gas Periodic Monitoring Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Combustion Sources Subject to Rules 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, 1146 – Emissions of Oxides of Nitrogen From Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, and 1146.1 – Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters.

(B) Conduct the diagnostic emission checks by a person who has completed an appropriate training program approved by South Coast AQMD in the operation of portable analyzers and has received a certification issued by the South Coast AQMD.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(C) Conduct the diagnostic test every 365 days or every 8760 operating hours, whichever occurs earlier.

(2) A diagnostic emissions check that finds the emissions in excess of those allowed by this rule or a South Coast AQMD permit condition shall not constitute a violation of this rule if an owner or operator corrects the problem and demonstrates compliance with another diagnostic emissions check within 72 hours from the time an owner or operator knew of excess emissions, or reasonably should have known, or shut down the ~~unit~~Unit by the end of an operating cycle, whichever is sooner. Any diagnostic emission check conducted by South Coast AQMD staff that finds emissions in excess of those allowed by this rule or a South Coast AQMD permit condition shall be a violation.

(m) Monitoring, Recordkeeping, and Reporting Requirements

(1) Operating Log

An owner or operator of a ~~unit~~Unit shall maintain the following daily records for each ~~unit~~Unit, in a manner approved by the Executive Officer:

(A) Time and duration of startup and shutdown events;

(B) Total hours of operation;

(C) Quantity of fuel; and

(D) Cumulative hours of operation to date for the calendar year.

(2) An owner or operator of a ~~facility~~Facility that elects to meet the NOx emission limits in an approved B-Cap pursuant to paragraph (e)(2) shall:

(A) Maintain CEMS for all applicable equipment or an enforceable method approved by the Executive Officer to determine daily mass emissions for those ~~unit~~Units without CEMS;

(B) Maintain daily records of mass emissions, in pounds (lbs) per day, from all ~~unit~~Units included in an approved B-Cap including:

(i) Emissions during start-ups, shutdowns, and maintenance;

(ii) CEMS data identified as invalid and justification;

(iii) Data substituted for missing data pursuant to paragraph (j)(5);

(C) Demonstrate compliance with the Facility BARCT Emission Target in the B-Cap on a daily basis from 365-day rolling average;

(3) An owner or operator subject to the interim emission rate pursuant to paragraph (f)(2) shall maintain the following daily records for each ~~unit~~Unit, in a manner approved by the Executive Officer:

(A) Actual daily mass emissions, in lbs., for all ~~b~~Boilers and ~~p~~Process ~~h~~Heaters with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour;

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(B) Combined maximum R~~r~~ated ~~h~~Heat ~~i~~Input for all ~~b~~Boilers and ~~p~~Process ~~h~~Heaters with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour; and

(C) Calculated interim NOx emission rate pursuant to Attachment A Section (A-2) of this rule.

(4) An owner or operator of a ~~unit~~Unit shall keep and maintain the following records on-site for five years, except that all data gathered or computed for intervals of less than 15 minutes shall be maintained for a minimum of 48 hours, and shall make them available to the Executive Officer upon request:

(A) CEMS data;

(B) Source tests reports;

(C) Diagnostic emission checks; and

(D) Written logs of startups, shutdowns, and breakdowns, all maintenance, service and tuning records, and any other information required by this rule.

(5) An owner or operator of a ~~b~~Boiler or ~~p~~Process ~~h~~Heater that is exempt from the applicable Table 1 emission limits pursuant to paragraphs (n)(5) and (n)(6), or an owner or operator of a flare that is exempt from the applicable Table 1 emission limits pursuant to subparagraph (n)(8)(A) shall:

(A) Within 90 days of [*DATE OF ADOPTION*], install and operate a non-resettable totalizing time meter or a fuel meter unless a metering system is currently installed and the fuel meter is approved in writing by the Executive Officer.

(B) Within 90 days of [*DATE OF ADOPTION*], each non-resettable totalizing time meter or a fuel meter required under subparagraph (m)(4)(A) that requires dependable electric power to operate shall be equipped with a permanent supply of electric power that cannot be unplugged, switched off, or reset except by the main power supply circuit for the building and associated equipment or the safety shut-off switch.

(C) Ensure that the continuous electric power to the non-resettable totalizing time meter or fuel meter required under subparagraph (m)(4)(A) may only be shut off for maintenance or safety.

(D) Within 90 days of [*DATE OF ADOPTION*], ensure that each non-resettable totalizing time meter or fuel meter is calibrated and recalibrate the meter annually, thereafter, based on the manufacturer's recommended procedures. If the non-resettable totalizing time or fuel meter was calibrated within one year prior to [*DATE OF ADOPTION*], the next calibration shall be conducted within one year of anniversary date of the prior calibration.

(E) Monitor and maintain hours of operation records as follows:

(i) For the hours per year validation, using a calibrated non-resettable

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totalizing time meter or equivalent method approved in writing by the Executive Officer; or

(ii) For the annual throughput limit equivalent to hours per year validation, using a calibrated fuel meter or equivalent method approved in writing by the Executive Officer.

(6) An owner or operator of a ~~v~~Vapor ~~i~~Incinerator that is exempt from the applicable Table 1 NOx emission limits pursuant to paragraph (n)(9) shall record:

(A) The annual throughput using a calibrated fuel meter or equivalent method approved in writing by the Executive Officer; and

(B) Emissions using a source test pursuant to subdivision (k) or by using a default emission factor approved in writing by the Executive Officer.

(7) An owner or operator of a ~~unit~~Unit subject to the compliance schedule in subparagraphs (d)(3)(B), (d)(4)(B), and (g)(3)(B) shall maintain records of burner replacement, including number of burners and date of installation.

(8) An owner or operator of a ~~u~~Unit subject to the compliance schedule in subparagraph (g)(3)(A) shall maintain records of the date the existing post-combustion control equipment was installed or replaced.

(n) Exemptions

(1) Boilers or Process Heater with a Rated Heat Input Capacity 2 MMBtu/hour or less The provisions of this rule shall not apply to an owner or operator of a ~~b~~Boiler or ~~p~~Process ~~h~~Heater with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity 2 MMBtu/hour or less that ~~are~~ is fired with liquid and/or gaseous fuel and used exclusively for space or water heating and is~~are~~ subject to Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters.

(2) Low-Use Boilers with a Rated Heat Capacity of less than 40 MMBtu/hour An owner or operator of a ~~b~~Boiler with a ~~r~~Rated ~~h~~Heat Input ~~c~~Capacity of less than 40 MMBtu/hour that operates 200 hours or less per calendar year, or with an annual throughput limit equivalent to 200 hours per calendar year, shall be exempt from the requirements in:

(A) Subdivisions (d) provided:

(i) The ~~b~~Boiler has an enforceable South Coast AQMD permit condition~~s~~ that limits the operating hours to 200 hours or the annual throughput equivalent to 200 hours; and

(ii) The ~~b~~Boiler operates in compliance with the permit conditions pursuant to clause (n)(2)(A)(i~~i~~).

(B) Subdivisions (k) and (l) provided the ~~u~~Unit is not included in an approved B-Cap.

(3) Low-Use Process Heater with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

An owner or operator of a ~~p~~Process ~~h~~Heater with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour that is fired at less than 15 percent of the ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity on an annual basis, shall be exempt from the applicable emission limits in Table 1, Table 2, and an approved B-Plan.

(4) An owner or operator of a FCCU that must bypass the post-combustion air pollution control equipment to conduct ~~b~~Boiler inspections required under California Code of Regulations, Title 8, Section 770(b) shall be exempt from the applicable Rule 1109.1 Emission Limits during the required ~~b~~Boiler inspections.

(5) FCCU Startup Heater

An owner or operator of a ~~p~~Process ~~h~~Heater which is used only for startup of a FCCU and that ~~p~~Process ~~h~~Heater is operated for 200 hours or less per calendar year shall be exempt from the requirements in:

(A) Subdivisions (d) provided:

(i) The ~~p~~Process ~~h~~Heater or ~~b~~Boiler has a South Coast AQMD permit that specifies conditions that limits the operating hours to 200 hours per calendar year or less; and

(ii) The ~~p~~Process ~~h~~Heater or ~~b~~Boiler operates in compliance with the permit condition pursuant to clause (n)(5)(A)(i).

(B) Subdivisions (k) and (l) provided the ~~u~~Unit is not included in an approved B-Cap.

(6) Startup or Shutdown Boilers at Sulfuric Acid Plants

An owner or operator of a ~~p~~Process ~~h~~Heater used for startup or a ~~b~~Boiler used during startup or shutdown at a sulfuric acid plant that does not exceed 90,000 MMBtu of annual ~~h~~Heat ~~i~~Input per calendar year shall be exempt from the requirements in subdivisions (d), (i), (j), and (k) provided:

(A) The ~~p~~Process ~~h~~Heater or ~~b~~Boiler has a South Coast AQMD permit that specifies conditions that limits the ~~h~~Heat ~~i~~Input to 90,000 MMBtu or lower per calendar year; and

(B) The ~~p~~Process ~~h~~Heater or ~~b~~Boiler operates in compliance with the South Coast AQMD permit condition specified in subparagraph (n)(6)(A).

(7) Boiler or Process Heater Operating Only the Pilot

An owner or operator of a ~~b~~Boiler or ~~p~~Process ~~h~~Heater operating only the pilot prior to startup or after shutdown shall be exempt from the emission limits in paragraphs (d)(3), (d)(4), Table 1, Table 2, Table 3, an approved B-Plan, or an approved B-Cap and may exclude those emissions from the rolling average calculation pursuant to Attachment A of this rule.

(8) Flares

(A) An owner or operator of a ~~f~~Flare that emits less than or equal to 550 pounds

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

of NOx or less per year shall be exempt from the requirements in subdivisions (d), (g) and (k), provided:

(i) The ~~f~~Flare has enforceable South Coast AQMD permit conditions that limits the emissions to not exceed 550 pounds of NOx per year; and

(ii) The ~~f~~Flare is in compliance with the permit condition pursuant to clause (n)(8)(A)(i).

(B) An owner or operator of an open ~~f~~Flare, which is an unshrouded ~~f~~Flare, shall not be required to conduct source testing pursuant to subdivision (k).

(9) Vapor Incinerators

An owner or operator of a ~~v~~Vapor ~~i~~Incinerator that emits less than 100 pounds of NOx per year shall be exempt from the requirements in subdivision (d) provided the ~~v~~Vapor ~~i~~Incinerator:

(A) Has enforceable South Coast AQMD permit conditions that limit NOx emissions to less than 100 pounds of NOx per year through operating hours or annual throughput; and

(B) Operates in compliance with the permit condition pursuant to subparagraph (n)(9)(A).

Commented [A11]: Some references are to "year" and some are "calendar year"

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

ATTACHMENT A

SUPPLEMENTAL CALCULATIONS

(A-1) Rolling Average Calculation for Emission Data Averaging

$$C_{Avg} = \sum_{i=t}^{t+N-1} C_i / N$$

Where:

C_{Avg} = The average emission concentration at time t

t = Time of average concentration (hours)

C_i = The measured or calculated concentration for a unit with a CEMS at the i^{th} subset of data; one-hour for a unit with an averaging time of 24 hours or less and 24-hour for a unit with an averaging time of greater than 24 hours

N = Averaging time (hours).

In order to calculate an average emission concentration at time t, the operator must have an elapsed operating period equal to or greater than time t.

(A-2) Interim NOx Emission Rate Calculation

An owner of operator shall calculate interim NOx emission rates as follows:

(A-2.1) Hourly Mass Emissions (lbs/hour)

Sum the actual annual mass emissions of all ~~boiler~~Boilers and ~~process~~Process ~~H~~Heaters with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour and any ~~boiler~~Boilers and ~~process~~Process ~~h~~Heaters with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity less than 40 MMBtu/hour that operate a certified CEMS, and divide by 8760 hours for lbs per hour.

(A-2.2) Combined Maximum Heat Input (MMBtu/hour)

Sum the combined maximum ~~r~~Rated ~~h~~Heat ~~i~~Input for all ~~boiler~~Boilers and ~~process~~Process ~~h~~Heaters with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity greater than or equal to 40 MMBtu/hour and any ~~boiler~~Boilers and ~~process~~Process ~~h~~Heaters with a ~~r~~Rated ~~h~~Heat ~~i~~Input ~~c~~Capacity less than 40 MMBtu/hour that operate a certified CEMS.

(A-2.3) Interim Facility Wide NOx Emission Rate (lbs/MMBtu)

Divide the Hourly Mass Emissions in Section (A-2.1) by the combined Maximum Heat Input in Section (A-2.2) to determine the interim NOx emission rate.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

ATTACHMENT B

CALCULATION METHODOLOGY FOR THE I-PLAN, B-PLAN, AND B-CAP

The purpose of this attachment is to provide details regarding how key elements of the I-Plan, B-Plan, and B-Cap are calculated. Key calculations provided in this attachment include: Baseline Unit Emissions and Baseline Facility Emissions; Final Phase Facility BARCT Emission Target; Total Facility NOx Emission Reductions; Phase I, Phase II, or Phase III Facility BARCT Emission Target; Phase I, Phase II or Phase III BARCT Equivalent Mass Emissions for a B-Plan; and Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions for a B-Cap.

(B-1) Baseline Unit Emissions and Baseline Facility Emissions

Baseline Unit Emissions shall be determined by the Executive Officer based on the applicable 2017 NOx Annual Emissions Reporting data, or another representative year, as approved by the Executive Officer, expressed in pounds per year. Baseline Facility Emissions are the sum of all the Baseline Unit Emissions subject to this rule~~ and shall not include Baseline Unit Emissions for units that are operational on and after [DATE OF ADOPTION]~~.

Commented [A12]: Believe this was accidental. As written, would result in BFE = sum of BUE – sum of BUE = 0 (assuming no change in operating units).

BFE = Baseline Facility Emissions
BUE = Baseline Unit Emissions

(B-2) Final Phase Facility BARCT Emission Target

The Final Phase Facility BARCT Emission Target is the Phase II Facility BARCT Emission Target for an I-Plan option with two phases or the Phase III Facility BARCT Emission Target for an I-Plan option with three phases. The Final Phase Facility BARCT Emission Target is used to establish the Phase II or Phase III BARCT Emission Target for a B-Cap. To establish the Final Phase Facility BARCT Emission Target, the owner or operator must select whether~~if~~ the basis of the emission target for each ~~unit~~ Unit will be based on Table 1 or Table 2 NOx concentration limits. The owner or operator shall only select Table 2 NOx concentration limits if the requirements of subparagraphs (d)(2)(A) and (d)(2)(B) for the Conditional NOx Limits are met or if the ~~u~~Unit is identified pursuant to subparagraph (d)(2)(C) and ~~in~~ Attachment D. For all other ~~u~~Units, the owner or operator shall use NOx limits from Table 1 as the basis of the Facility BARCT Emission Target. To calculate the Final Phase Facility BARCT Emission Target for B-Cap, the owner or operator shall use NOx concentration limits from ~~of~~ Table 1 for the ~~u~~Units that will be decommissioned.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(B-2.1) The Final Phase Facility BARCT Emission Target for a ~~facility~~ Facility complying with NOx emission limits in Table 1, an approved B-Plan or an approved B-Cap shall be calculated using the following equation:

$$\text{Final Phase Facility BARCT Emission Target} = \sum_{i=1}^{N} \left(\frac{C_{\text{Table 1 or Table 2}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions} \right)_i$$

Where:

N	= Number of included ~~u~~Units in B-Plan or B-Cap
$C_{\text{Table 1 or Table 2}}$	= The applicable NOx concentration limit for each ~~u~~Unit i included in B-Plan or B-Cap
C_{Baseline}	= Representative NOx Concentration as defined in subdivision (c) for ~~u~~Unit i included in B-Plan
Baseline Unit Emissions	= Baseline Unit Emissions for ~~u~~Unit i as defined in subdivision (c) and included in the I-Plan, B-Plan or B-Cap as determined pursuant to section (B-1).

(B-3) Calculating Total Facility NOx Emission Reductions

Total Facility NOx Emission Reductions is the total reduction in NOx mass emissions per ~~facility~~Facility or ~~f~~Facilities ~~with~~ With ~~t~~The ~~s~~Same ~~o~~Ownership that would have been achieved if all ~~u~~Units met the NOx concentration limits in Table 1 or Table 2 of this rule based on the Baseline Facility Emissions.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(B-3.1) For a F~~f~~acility complying with NOx emission limits in Table 1 or Table 2, an approved B-Plan or an approved B-Cap, the Total NOx Emission Reductions is the difference between Baseline Facility Emissions and the Final Phase Facility BARCT Emission Target.

$$\text{Total Facility NOx Emission Reductions}$$
$$= \text{Baseline Facility Emissions}$$
$$- \text{Final Phase Facility BARCT Emission Target}$$

(B-4) Calculating Phase I, Phase II, or Phase III Facility BARCT Emission Target The Phase I, Phase II, or Phase III Facility BARCT Emission Targets are the total NOx mass emissions per F~~f~~acility based on the Total Facility NOx Emission Reductions and the Percent Reduction Target of Phase I, Phase II or Phase III of an I-Plan option in Table 6. ~~For a B-Cap, each phase Facility BARCT Emission Targets shall be reduced by 10 percent.~~

(B-4.1) For the B-Plan, the Phase I Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Facility Emissions and applying the selected I-Plan Phase I Percent Reduction Target from Table 6 to the Total NOx Emission Reductions.

$$\text{Phase I Facility BARCT Emission Target}_{B-Plan}$$
$$= \text{Baseline Emissions}$$
$$- (\text{Phase I Percent Reduction Target}$$

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(B-4.2) For the B-Cap, the Phase I Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Facility Emissions and applying the selected I-Plan Phase I Percent Reduction Target from Table 6 to the Total NOx Emission Reductions~~, less 10 percent~~.

$$\text{Phase I Facility BARCT Emission Target}_{B-Cap}$$
$$= [\text{Baseline Emissions}$$
$$- (\text{Phase I Percent Reduction Target}$$

(B-4.3) For the B-Plan, if Phase II is not final phase, Phase II Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Emissions and applying the selected I-Plan Phase II Percent Reduction Target from Table 6 to the Total NOx Emission Reductions.

$$\text{Phase II Facility BARCT Emission Target}_{B-Plan}$$
$$= \text{Baseline Emissions}$$
$$- (\text{Phase II Percent Reduction Target}$$

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(B-4.4) For a B-Cap, if Phase II is not final phase, Phase II Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Emissions and applying the selected I-Plan Phase II Percent Reduction Target from Table 6 to the Total NOx Emission Reductions.

$$\text{Phase II Facility BARCT Emission Target}_{B-Cap}$$
$$= [\text{Baseline Emissions}$$
$$- (\text{Phase II Percent Reduction Target}$$

(B-4.5) For a B-Plan, for the final phase, Phase II for the two phase I-Plan or Phase III for the three phase I-Plan, the Phase II or Phase III Final Facility BARCT is the Final Phase Facility BARCT Target as calculated in Section B-2.1.

$$\text{Phase II or Phase III Facility BARCT Emission Target}_{B-Plan}$$
$$= \text{Final Phase Facility BARCT Emission Target}$$

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(B-4.6) For a B-Cap, for the final phase, Phase II for the two phase I-Plan or Phase III for the three phase I-Plan, the Phase II or Phase III Final Facility BARCT is the Final Phase Facility BARCT Target as calculated in Section B-2.1.

$$\text{Phase II or Phase III Facility BARCT Emission Target}_{B-Cap} = (\text{Final Phase Facility BARCT Emission Target}) \cancel{\times 0.9}$$

(B-5) Calculating Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions for a B-Plan

The Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions are the total remaining NOx mass emissions per ~~facility~~Facility that incorporates emission reduction strategies designed to meet Phase I, Phase II, or Phase III target reductions in an I-Plan. The Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions incorporate the Alternative BARCT NOx Limit for Phase I, Phase II, or Phase III each of the ~~u~~Units included in different phases of the I-Plan. The Alternative BARCT NOx Limits are the ~~unit~~ Unit specific NOx concentration limit that are selected by the owner or operator in the B-Plan to achieve the Facility BARCT Emission Targets in the aggregate, where the NOx and CO concentration limits will include the corresponding percent O_2 correction based on the averaging time pursuant to Table 1 or subdivision (k), whichever is applicable. For the B-Plan, decommissioned units shall be removed from the Baseline Facility Emissions and the Facility BARCT Emission Targets.

(B-5.1) For a B-Plan, the Phase I BARCT Equivalent Mass Emissions for all units included in a B-Plan shall be calculated using the following equation:

$$\text{Phase I BARCT Equivalent Mass Emissions}_{B-Plan} = \sum_{i=1}^{N} (\frac{C_{\text{Phase I Alternative BARCT Emission Limit}}}{C_{\text{Baseline}}}$$

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

× Baseline Unit Emissions)
i

Where:

N	=	Number of included units in B-Plan under Phase I
$C_{Phase\ I\ Alternative\ BARCT\ Emission\ Limit}$	=	The applicable Alternative BARCT NOx Limit in an approved B-Plan for unit i included in the B-Plan
$C_{Baseline}$	=	Representative NOx Concentration as defined in subdivision (c) for unit i included in the B-Plan
Baseline Unit Emissions	=	Baseline Unit Emissions for unit i as Defined in subdivision (c) and included in the B-Plan.

(B-5.2) For a B-Plan, the Phase II and if applicable, Phase III Equivalent Mass Emissions for each ~~u~~Unit included in a B-Plan shall be calculated using the equation for Section B-5.1, with the use of the Alternative BARCT NOx Limit for Phase II and Phase III, if applicable.

(B-6) Calculating Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions for a B-Cap

The Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions are the total remaining NOx mass emissions per ~~facility~~Facility that incorporates emission reduction strategies. The Phase I, Phase II, and Phase III BARCT B-Cap Annual Emissions must be at or below the respective Phase I, Phase II, or Phase III Facility BARCT Emission Targets an I-Plan. Under the B-Cap, there are three emission reduction strategies that can be used to meet the Facility BARCT Emission Targets: Establishing an Alternative BARCT NOx Limit, Decommission Units, and Reducing Throughput for Units. The Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions calculation for the B-Cap acknowledges the three emission reduction strategies for each phase of the I- Plan. The Alternative BARCT NOx Limits are the ~~u~~Unit specific NOx concentration limits that are selected by the owner or operator in the B-Cap to achieve the Final Phase Facility BARCT Emission Target in the aggregate, where the NOx concentration limit will include the corresponding percent O_2 correction, CO emission limit, and averaging time per Table_1. The emission reductions from Decommission Units shall be incorporated in B-Cap pursuant to

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

section (B-2.2). Other reductions in mass emission reductions to demonstrate that the BARCT B-Cap Annual Emissions include emission reductions from reduced throughput, efficiency, reduced capacity, and any other strategy to reduce mass emissions.

(B-6.1) The Phase I BARCT B-Cap Annual Emissions for each unit included in a B-Cap shall be calculated using the following equation where the Unit Throughput Reductions calculated pursuant to Section B-7.

$$\text{Phase I BARCT B} - \text{Cap Annual Emissions}_{B-Cap}$$
$$= \sum_{i=1}^{N} (\frac{C_{\text{Phase I Alternative BARCT Emission Limit}}}{C_{\text{Baseline}}}$$

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

$$\times \text{ Baseline Unit Emissions})_i$$
$$+ (0_{\text{Decommissioned Units}})_i$$
$$- (\text{Throughput or Other Reductions})$$

Where:

N = Number of included ~~u~~Units in B-Cap under Phase I

$C_{\text{Phase I Alternative BARCT Emission Limit}}$ = The applicable Alternative BARCT NOx Limit in an approved B-Cap for ~~unit~~ Unit i included in the B-Cap

C_{Baseline} = Representative NOx Concentration as defined in subdivision (c) for ~~u~~Unit i included in the B-Cap

Baseline Unit Emissions = Baseline Unit Emissions as defined in subdivision (c) and for ~~u~~Unit i included in the B-Cap

Throughput or Other Reductions = Emission reductions occurred from other than reducing the concentration limit.

(B-6.2) For a B-Cap, the emission reductions the Phase II and if applicable, Phase III BARCT B-Cap Annual Emissions for each unit included in a B-Cap shall be calculated using the equation for Section B-6.1, with the use of three emission reduction strategies for Phase II and Phase III, if applicable.

(B-7) Emissions Reductions from Decommissioned Unit

For a B-Cap, emission reductions from decommissioned ~~u~~Units can be used to meet a Phase I, Phase II, or Phase III Facility BARCT Emission Target. The amount of emission reductions from a decommissioned ~~u~~Unit shall be determined using the equation below.

Emission Reductions from Decommissioned Units

$$= \sum_{i=1}^{N} \left(\frac{C_{\text{Table 1}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions}\right)_i$$

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Where:

N = Number of decommissioned ~~u~~Units in B-Cap

$C_{Table\ 1}$ = Table 1 NOx concentration limit for ~~u~~Unit i

$C_{Baseline}$ = Representative NOx Concentration as defined in subdivision (c) for ~~u~~Unit i included in an approved B-Cap

Baseline Unit Emissions = Baseline Unit Emissions for ~~u~~Unit i as defined in subdivision (c) and included in an approved B-Cap.

(B-8) Unit Reductions for Conditional NOx and CO Limits in Table 2

An owner or operator of a ~~u~~Unit in a B-Plan that is demonstrating that the Unit Reduction is less than the thresholds specified in clauses (d)(2)(A)(i) or (d)(2)(A)(ii) shall calculate the Unit Reduction using the following equation:

$$\text{Unit Reduction} = \left(1 - \frac{C_{\text{Table 1}}}{C_{\text{Baseline}}}\right) \times \text{Baseline Unit Emissions}$$

Where:

$C_{Table\ 1}$ = The applicable Table 1 NOx concentration limit the unit

$C_{Baseline}$ = Representative NOx Concentration for the unit

Baseline Unit Emissions = Baseline Unit Emissions.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

ATTACHMENT C

FACILITIES EMISSIONS – BASELINE AND TARGETS

(C-1) Baseline Facility Emissions

Table C-1 provides the Baseline Mass Emissions for Facilities with six or more units. Baseline Facility Emissions in Table C-1 are based on 2017 reported emissions for Rule 1109.1 units. A year other than 2017 was used for units where the 2017 reported emissions were not representative of normal operations.

TABLE C-1: Baseline Mass Emissions for Facilities with Six or More Units

Facility	Facility ID	Baseline Facility Emissions (2017) (tons/year)
AltAir Paramount, LLC	187165	28
Chevron Products Co.	800030	701
Lunday-Thagard Co. DBA World Oil Refining	800080	26
Phillips 66 Company/Los Angeles Refinery	171109	386
Phillips 66 Co/LA Refinery Wilmington PL	171107	462
Tesoro Refining and Marketing Co., LLC – Carson	174655	636
Tesoro Refining and Marketing Co., LLC – Wilmington	800436	674
Tesoro Refining and Marketing Co., LLC – Sulfur Recovery Plant	151798	8
Tesoro Refining and Marketing Co., LLC, Calciner	174591	261
Torrance Refining Company LLC	181667	899
Ultramar Inc.	800026	248
Valero Wilmington Asphalt Plant	800393	5

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

ATTACHMENT D

UNITS QUALIFY FOR CONDITIONAL LIMITS IN B-PLAN AND B-CAP

TABLE D-1: Units That Qualify for Conditional Limits in B-Plan

Facility ID	Device ID	Size (MMBtu/hr)
171109	D429	352
171109	D78	154
174655	D1465	427
174655	D419	52
174655	D532	255
174655	D63	300
181667	D1236	340
181667	D1239	340
181667	D231	60
181667	D232	60
181667	D234	60
181667	D235	60
181667	D950	64
800026	D1550	245
800026	D6	136
800026	D768	110
800030	D159	176
800030	D160	176
800030	D161	176
800030	D643	220
800030	D82	315
800030	D83	315
800030	D84	219
800436	D1122	140
800436	D384	48
800436	D385	24
800436	D388	147
800436	D388	147
800436	D770	63
800436	D777	146

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE D-2: Units That Qualify for Conditional Limits in B-Cap

Facility ID	Device ID	Size (MMBtu/hr)
171107	D220	350
171107	D686	304
171109	D429	352
171109	D78	154
171109	D79	154
174655	D33	252
174655	D419	52
174655	D421	82
174655	D532	255
174655	D539	52
174655	D570	650
181667	D1236	340
181667	D1239	340
181667	D231	60
181667	D232	60
181667	D234	60
181667	D235	60
181667	D920	108
181667	D950	64
800026	D1550	245
800026	D378	128
800026	D429	30
800026	D430	200
800026	D53	68
800026	D6	136
800026	D768	110
800026	D98	57
800030	D453	44
800030	D643	220
800030	D82	315
800030	D83	315
800030	D84	219
800436	D1122	140
800436	D158	204
800436	D250	89
800436	D33	252
800436	D384	48
800436	D385	24
800436	D386	48
800436	D387	71
800436	D388	147
800436	D770	63
800436	D777	146

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Staff Response to Commenter Letter #6:

Response to Comment 6-1:

PR 1109.1 was revised to move the compliance dates in subdivision (d) – Emission Limits to subdivision (f) Compliance Schedule (formerly subdivision (g)). Staff retained the submittal dates for the I-Plan, B-Plan and B-Cap within their respective subdivisions.

Response to Comment 6-2:

Staff agrees that the term "deemed complete" is a very specific term within the South Coast AQMD permitting process. PR 1109.1 does not use the term "deem complete" but references a complete permit application, meaning all necessary elements are included in the permit application. PR 1109.1 has been revised to "submit a complete permit application" and a discussion has been added in the staff report that further explains that a "complete permit application" does not mean that the permit application has been "deemed complete."

Response to Comment 6-3:

Any unit that is listed in Table D-1 or Table D-2 must submit a permit application based on the schedule in an approved I-Plan. In addition, Units identified in Table D-1 and D-2 may have an alternative BARCT NOx limit higher than the Table 2 conditional NOx concentration limits. Units in Table D-1 are units staff identified as qualifying for the Table 2 conditional NOx concentration limits. These units had high cost-effectiveness values because they either had a low emission reduction potential because units were operating close to the Table 1 NOx concentration limit or had high capital costs. Units in Table D-2 are for those operators that select a B-Cap compliance option with I-Plan Option 4. Units in Table D-2 have annual average NOx concentrations based on representative data that is at or below 25 ppm. Although operators are limited to the units listed in Table D-2, operators can establish an alternative BARCT NOx concentration limit for units listed in Table D-2 during implementation of the I-Plan and establish an alternative BARCT NOx concentration limit higher than the Table 2 conditional NOx concentration limits provided it does not exceed the maximum alternative BARCT NOx concentration limits for a B-Cap pursuant to Table 6 of PR 1109.1. I-Plan Option 4 is unique compared to the other I-Plan options as it requires a 50 percent reduction by January 1, 2024 which will achieve NOx reductions six months earlier than operators that are meeting Table 2 conditional NOx concentration limits under subparagraph (f)(3) (assuming 18 months for the Executive Officer to issue a permit to construct and 18 months to meet the NOx limit). In addition, although NOx concentration limits may be higher than the limits in Table 2 for units listed in Table D-2 of PR 1109.1, operators under the B-Cap have the additional obligation to demonstrate that actual emissions are below the facility BARCT emission target.

Operators that do not meet the criteria for units listed in Table D-1 or Table D-2, must establish a NOx limit that is at or below Table 2 conditional NOx limits. Conditional NOx limits were developed to help reduce the average cost-effectiveness and to address units with the worst cost-effectiveness. In addition to the units staff identified through the cost-effectiveness analysis (Table D-1 Units) and units in a B-Cap that will use I-Plan Option 4 (Table D-2 Units), PR 1109.1 allows operators to identify units that can meet Table 2 conditional NOx limits, that meet the conditions of paragraph (d)(3). This provision was added to recognize that there may be additional units that can achieve the Table 2 conditional NOx limits that have existing pollution controls and can make minor modifications to the existing pollution controls, if any, to meet the Table 2 conditional NOx limits. Use of Table 2 conditional NOx limits will increase the facility BARCT emissions target. Staff believes that operators that use a conditional NOx limit beyond what is assumed in the cost-effectiveness analysis should be held to the conditional NOx limit. If the operator cannot meet the conditional NOx limit within the time allowed under PR 1109.1, then the unit likely needed additional pollution controls and should then be required to meet the Table 1 NOx concentration limit.

The rule does provide some flexibility in regard to the Table 2 conditional limits. Any unit that is listed in Table D-1 or Table D-2 must submit a permit application based on the schedule in an approved I-Plan. In addition, units identified in Table D-1 and D-2 may have an alternative BARCT NOx limit higher than the Table 2 conditional NOx concentration limits.

Response to Comment 6-4:

One of the most important conditional provisions for using the Table 2 conditional NOx concentration limits is to ensure units with new SCR installations meet Table 1 NOx concentration limits. Most SCR installations permitted under the RECLAIM program do not include NOx permit limits; therefore, the rule language change requested by WSPA would allow most new SCR installation to elect to comply with the Table 2 Conditional limits even though the new SCRs should be able to achieve Table 1 limits. The third-party engineering consultant, Norton Engineering, concluded that LNBs can achieve 40 – 50 ppmv NOx concentrations under non-optimal conditions and up to 30 ppmv NOx under optimal conditions. Norton Engineering also stated a single bed SCR can achieve at least 92% NOx emission reductions; however, using multiple catalyst bed with additional ammonia injection grid can increase the NOx emission reductions to above 94%. Considering the emission reduction capability of NOx control technologies, it is reasonable to expect units where the permit to construct was issued after 2015, will consequently benefit from the installation of modern control technologies that can achieve Table 1 NOx concentration limits. There are also alternative plans in the rule that allow facilities to use a higher NOx concentration limit than Table 1 NOx limits. Considering the flexibility provided in the PR 1109.1 allowing for alternative plans, a unit is not tied to meet a specified endpoint. In addition, the 2015 NOx shave BARCT assessment, which was based on a programmatic BARCT assessment, concluded a 2 ppmv NOx limit is technically feasible and cost-effective, as did the initial BARCT assessment under PR 1109.1. Facilities should have been striving to achieve 2 ppmv NOx for all units with new SCR installations. Staff is concerned that allowing facilities to meet Table 2 conditional NOx limits for units with new SCR installation would create a significant loophole which can lead to weakening of PR 1109.1. Based on the reasons cited above and the rule construct, staff does not believe any newly installed SCR will have to be replaced; therefore, there will not be any stranded assets for recently installed NOx control equipment.

Response to Comment 6-5:

Staff concurs with this comment and revised this provision.

Response to Comment 6-6:

Staff acknowledges that there are two process heater that do not currently meet the 40 ppmv proposed limits. Staff presented the cost-effective assessment for those units to retrofit to 40 ppmv in Appendix B of the staff report and revised the main body of the staff report to reflect that analysis. The compliance dates for the process heaters were revised in the draft rule to accommodate those units that will require the installation of controls. PR 1109.1 has the following pathways for the process heaters <40 MMBtu/hour to comply with the 40 ppmv NOx and interim limits:

Interim limit:

- Comply with the 0.03 pound/MMBtu facility-wide emission rate for any boiler or process heater <40 MMBtu/hour that operates with a certified CEMS;
- Facilities complying with a B-Cap will comply with the interim cap instead of the interim limits; or
- Comply with the new interim limit of 60 ppmv for process heaters <6 MMBtu/hour.

40 ppmv NOx limit:

- Comply with the limit based on the revised schedule in (f)(2)
- Comply with the limit based on the schedule in the I-Plan where the facility BARCT emission target for that unit is based on:
  - 40 ppmv if the unit is included in phase I of the I-Plan and no further emission reduction credit is taken for the unit in phase II or phase III; or
  - 9 ppmv if the unit is included in any phase other than phase I.

Response to Comment 6-7:

Please see the response to comment 6-6 and the BARCT assessment in Appendix B.

Response to Comment 6-8:

Please see the response to comment 6-6.

Response to Comment 6-9:

Staff did conduct and present the BARCT assessment for boilers and process heaters to meet the 5 ppmv and 9 ppmv NOx limits in Working Group Meeting #9. The assessment concluded those NOx limits are cost effective if the limits are effective upon burner replacement. The 5 ppmv NOx limits for boilers has been demonstrated in practice; however, the 9 ppmv limit for process heaters is a technology forcing limit. The BARCT emission levels can be technology forcing NOx concentration limits, meaning the limits can be based on emerging technology provided the NOx limit is achievable by the compliance date. Emerging technology is technology that can achieve emission reductions but is not widely available at the time the NOx limit is established and the rule is adopted. When South Coast AQMD adopts rules with technology forcing emission limits, the limits are given a future implementation date to allow time for the technology to develop. BARCT limits evolve over time as technology improves or new pollution control technologies emerge; setting future effective emission limits is appropriate and the approach has been used, and upheld, in other rules. South Coast AQMD adopted volatile organic compound (VOC) limits in Rule 1113 – Architectural Coatings in 2002 with a future effective date of July 1, 2006 based on emerging technology (e.g., reformulated coatings). The technology to meet the lower VOC limits was commercially available but had performance issues that had yet to be overcome. The American Coating Association sued the South Coast AQMD for adopting technology forcing BARCT limits, but the South Coast AQMD prevailed in the Supreme Court of California upholding the ability to adopt technology forcing BARCT limits.

Further, staff believes the implementation of the B-Plan and B-Cap in PR 1109.1 will help incentivize operators to accelerate introduction and commercialization of emerging technologies. Staff will monitor the development of the emerging technologies and will include in the Resolution a commitment to report on the status of the emerging technologies in 2029 and conduct a technology assessment if these technologies are not being commercialized.

Response to Comment Response 6-10:

Staff does not agree with this comment. Units in both the B-Plan and the B-Cap that meet the conditions for the Table 2 are held to the Table 2 conditional NOx limits unless the units are listed in Table D-1 or Table D-2 where a facility can elect to assign a higher NOx limit than Table 2 when establishing the facility BARCT emission target, provided the facility offsets those higher limits with units that are over controlled. In a B-Cap, facilities are allowed to take "credit" from decommissioned units, so PR 1109.1 includes additional limitations when selecting the alternative BARCT NOx limits. Requiring all units to meet either the maximum NOx limits or the Table 2 conditional limits ensures all units have some level of NOx emission controls.

Response to Comment 6-11:

Staff disagrees with this comment. PR 1109.1 only allows a facility to take "credit" for decommissioned units if they are complying with a B-Cap. In a B-Cap, emission reductions associated with decommissioned units allow other units within the B-Cap to establish a higher alternative BARCT NOx limit and have higher NOx mass emissions. PR 1109.1 requires the facility BARCT emission target for decommissioned units to be calculated based on the applicable Table 1 NOx emissions to minimize the amount of "credit" generated from the decommissioned unit that can be used to offset emission reductions that otherwise would have been required. In addition, since units that can use Table 2 conditional limits are already performing under those limits, allowing facilities to use Table 2 conditional NOx limits to establish the facility BARCT emission targets for decommissioned units under B-Cap would create extra emission reduction "credits" in B-Cap and decrease the overall emission reductions.

Response to Comment 6-12:

Under the B-Cap, an operator can decommission or shutdown units to meet the facility BARCT emission target. If a facility were to decommission a unit, the emissions budget for that decommissioned unit can be used to have a higher alternative NOx concentration limit for another unit. Operators that decommission more units will be able to select higher alternative NOx concentration limits on more units, as compared to an operator with little or no decommissioned units. In addition, each unit under the B-Cap will receive an emissions budget. Units that are decommissioned will have an emissions budget in the facility BARCT emissions target based on the NOx concentration limit in Table 1. Safeguards are needed to ensure an operator that is adding a new unit is not receiving an increase in the B-Cap and the emissions budget. It would not be equitable that the emissions budget from a decommissioned unit was used to allow another unit not to install pollution controls, and later, install a unit that is functionally similar to the unit that was decommissioned. PR 1109.1 does not preclude an operator from adding New Units, but rather, the rule requires certain conditions be met if a New Unit subject to PR 1109.1 is installed. PR 1109.1 has been modified since the preliminary draft staff report and prevents an operator installing a new unit unless:

- The BARCT equivalent mass emissions are below the facility BARCT emission target for each phase of the I-Plan;

- The new unit is not functionally similar to any unit that was decommissioned in the approved B-Cap;
- The total amount of NOx emission reductions from units that were decommissioned, represents 15 percent or less of final phase facility BARCT emission target in an approved B-Cap; or
- The new unit is functionally similar to any unit that was decommissioned and is included in the BARCT B-Cap annual emissions with no increase in the facility BARCT emission target.

Response to Comment 6-13:

Staff concurs and revised the requirements to clarify that two interim emission limits do not apply to boilers and process heaters < 40 MMBtu/hour.

Response to Comment 6-14:

Staff concurs with this suggestion and restructured the rule language.

Response to Comment 6-15:

Staff disagrees with this comment as approval of the I-Plan, B-Plan, and B-Cap will require more than just ensuring the facilities provided all of the required elements. South Coast AQMD must also ensure the alternative BARCT NOx limits, facility BARCT emission targets, BARCT equivalent mass emissions and BARCT B-Cap annual emission were calculated correctly and based on reasonable assumptions. There are many variables in PR 1109.1 plans, approval is not just an administrative approval process.

Response to Comment 6-16:

Staff clarified the language to indicate that PR 1109.1 requires source testing quarterly during the first 12 months of being subject to the NOx concentration limit, and operators can source test annually thereafter provided the operator had four consecutive quarterly source tests to demonstrate compliance with CO, NOx, and ammonia concentration limit. The intent was not to require quarterly testing thereafter. This source testing schedule is consistent with Rule 1134 – Turbines and Rule 1146 – Boilers and Process Heaters. Units at petroleum refineries and at facilities with related operations to petroleum refineries should not have more lenient source test requirements than other facilities.

Response to Comment 6-17:

Staff disagrees with this comment. While some NOx landing rules were initially adopted with ammonia limits, staff decided to remove the ammonia limits from the source-specific rules and allow operators to establish the ammonia concentration limit during permitting. Although ammonia concentration limits have been removed from source-specific rules, the source testing requirement was retained in these rules. In addition, all recent NOx landing rule are being adopted without ammonia limits but including ammonia source testing schedules similar to what is being proposed in PR 1109.1.

Response to Comment 6-18:

Staff concurs and revised this section.

Response to Comment 6-19:

Based on discussions with U.S. EPA and review of U.S. EPA's January 2001 guidance for EIPs titled "Improving Air Quality with Economic Incentive Programs" referred herein as "EIP Guidance," the B-Cap is an Economic Incentive Program (EIP). Section 1.2 of the EIP Guidance states that, "You should follow this guidance if you are developing an EIP that you intend to include in a SIP as a means of achieving emission reductions to meet your SIP or SIP related requirements or as a means for providing sources with compliance flexibility for existing SIP requirements." The B-Cap is a discretionary EIP that was developed to provide compliance flexibility in achieving greater emission reductions than those that would occur if the operator were to meet the specified NOx concentration limits in Table 1 and the conditional NOx concentration limits allowed under Table 2. This additional compliance flexibility is added to help address the high capital cost associated with installation of pollution controls needed to meet NOx limits under PR 1109.1. This is consistent with the purpose of an EIP which is to allow sources compliance flexibility to meet SIP requirements more cost effectively.

The B-Cap is a combination of an emissions averaging and a source-specific cap and trade EIP. The B-Cap is an emission averaging program EIP as it allows operators to select an alternative BARCT NOx limit for each unit and requires the operator to demonstrate that mass emissions for all units in the B-Cap are in aggregate, below the Facility BARCT Emission Target. It is also a source-specific cap and trade EIP as it allows all units within the B-Cap alternatively demonstrate compliance with Table 1 and Table 2 NOx concentration limits through a mass-based emissions cap and applies to one facility with more than one owner and applies only to stationary sources. The B-Cap addresses equipment categories or units that must operate under a mass emissions cap and allows a variety of emission reduction strategies to demonstrate that mass emissions are below the mass cap or facility BARCT emission target. Use of the different emission reduction strategies include lowering the NOx concentration limit of individual units, shutting down individual units, and other emission reduction strategies such as reduction in throughput, increased efficiency, reduction in capacity, and any strategy that can reduce mass emissions. Use of these various emission reduction strategies allows for other units within the B-Cap to have higher NOx concentration limits for individual units.

The B-Cap is a trading EIP. An emissions averaging program and a source cap and trade program are both trading EIPs. Section 7.1 of the EIP Guidance defines a trading EIP as "a program that involves at least two emission units." The EIP Guidance explains that a trading EIP is where one emission unit with an emission reduction obligation uses emission reductions at different emission unit to meet these emission obligations. The EIP Guidance specifically states that, "There are four main types of emission trading programs: Emission averaging; Source-specific emission caps; Multi-source emission cap-and-trade; Open market trading." By allowing units to make greater emission reductions on some units to allow less emission reductions for other units to meet the facility BARCT emission target, the B-Cap is consistent with an emissions trading EIP.

For compliance flexibility EIPs, an environmental benefit means reducing the amount of surplus emission reductions generated for use in the EIP by at least 10 percent. The EIP Guidance does require that all EIPs demonstrate an environmental benefit. PR 1109.1 includes a 10 percent environmental benefit for the B-Cap that increases the facility emission reductions for each phase by 10 percent. Staff agrees that the EIP Guidance requires that a trading EIP in a nonattainment area that is needing and lacking an approved attainment demonstration (NALD) to incorporate an extra 10 precent reduction in emissions as the environmental benefit. Staff does not agree that the

EIP Guidance prohibits a trading EIP that is not a NALD to incorporate a 10 percent reduction in emissions as an environmental benefit. Section 4.3 of the EIP Guidance states, that a trading EIP that does not cover nonattainment areas that are NALD "can require a 10 percent extra reduction in emissions, or it can implement other provisions." Based on discussions with U.S. EPA, for the B-Cap, it was decided that reducing the Facility BARCT Emission Target by 10 percent is the most appropriate environmental benefit for the B-Cap since PR 1109.1 is designed to reduce NOx emissions, and NOx emission reductions are needed as NOx is a precursor to ozone, and the South Coast Air Basin is designated as extreme nonattainment with the ozone National Ambient Air Quality Standard.

The I-Plan does not achieve greater or more rapid emission reductions since the I-Plan provides an alternative to submitting a permit application for each unit before July 1, 2023, which is the baseline for evaluating rapid emission reductions. Staff agrees that implementation of I-Plan Option 4 does require a 50 percent of the required reductions by January 1, 2024. However, I-Plan Option 4 has two additional compliance dates to submit permit applications by January 1, 2025 and January 1, 2028 which is well after the July 1, 2023 compliance date in PR 1109.1 paragraph (d)(1). Incorporating a provision that would show greater or more rapid emission reductions that are more aggressive than PR 1109.1 paragraph (d)(1) would be very challenging for operators, and therefore, this option was not suggested as an environmental benefit.

The EIP Guidance Section 7.3(a) states that it must be demonstrate that "your EIP has resulted in more reductions than would have occurred without the program." The baseline for determining surplus emission reductions is direct compliance with meeting the NOx limits in Table 1 and the conditional NOx limits in Table 2 since the B-Cap is an alternative to meeting the NOx limits in Table 1 and Table 2. If an operator were to meet the NOx limits in Table 1 and Table 2, there is no "credit" for units that are decommissioned. Emission reductions from a decommissioned unit would be in addition to the NOx reductions that would be achieved from meeting the NOx limits in Table 1 and Table 2. Although units that are permanently decommissioned and not replaced with a functionally similar unit will reduce NOx and other pollutants, emission reductions from decommissioned units are not an environmental benefit relative to the baseline reductions associated meeting the NOx limits in Table 1 as specified in paragraph (d)(1) and the conditional NOx limits in Table 2 as specified in subparagraphs (d)(2)(A) and (d)(2)(B).

Under the B-Cap, emission reductions associated with decommissioned units allows other units within the B-Cap to establish a higher alternative NOx emission limit and have higher NOx mass emissions. The increase in mass emissions for the other units in the B-Cap will accordingly also have co-pollutant emission increases, which eliminates any benefit associated with the decommissioned unit and therefore would not be an appropriate demonstration of an environmental benefit. Specifically requiring an additional 10 percent reduction of the BARCT facility emission target ensures that an environmental benefit of NOx emission reductions will occur.

The South Coast AQMD has the obligation to ensure that PR 1109.1 can be approved by CARB and U.S. EPA to be incorporated into the State Implementation Plan (SIP). Staff has discussed the provisions of the B-Cap with both agencies and they concur that the additional 10 percent reduction in the BARCT facility emission target is appropriate for the B-Cap.

Response to Comment 6-20:

Staff appreciates the comments on the rule language and took them under consideration.

Comment Letter #7:

Tesoro Refining & Marketing Company LLC
A subsidiary of Marathon Petroleum Corporation

Los Angeles Refinery – Carson Operations
2350 E. 223rd Street
Carson, California 90810
310-816-8100

September 17, 2021

VIA Certified Mail and eMail (*wnastri@aqmd.gov*)
Return Receipt Requested

Wayne Nastri
Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Comments on SCAQMD Preliminary Draft Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Industries – And Related Proposed Rule 429.1 and Proposed Amended Rules 1304 and 2005 (Revision Date: August 20, 2021)

Dear Mr. Nastri:

On behalf of Tesoro Refining & Marketing Company LLC, a wholly owned subsidiary of Marathon Petroleum Corporation (collectively, "MPC"), MPC appreciates this opportunity to provide South Coast Air Quality Management District (SCAQMD) with comments on the Preliminary Draft Proposed Rule 1109.1 Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Industries (PR 1109.1) and the related proposed amended rules that were issued by the SCAQMD on August 20, 2021 (i.e., Proposed Rule 429.1 and Proposed Amended Rules 1304 and 2005).[1] Throughout the rulemaking process, MPC staff continues to be active participants in PR 1109.1 working group meetings and discussions with SCAQMD staff.

This set of comments, which supplements MPC's four previous comment letters submitted to SCAQMD on December 22, 2020, February 1, 2021, April 7, 2021, and May 12, 2021, focuses on several concerns that we outline below. Attachment 1 of this letter is a proposed mark-up of PR 1109.1 in red-line format that corresponds to MPC's comments.

1. **If U.S. EPA's Environmental Incentive Programs (EIP) Guidance[2] is applicable to the Best Available Retrofit Control Technology (BARCT) Equivalent Mass Cap Plan (B-Cap), environmental benefit can be demonstrated by other options and not only by the currently** 7-1

[1] SCAQMD, "Preliminary Draft Proposed Rule 1109.1," http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pd_pr1109-1_75.da y.pdf?sfvrsn=6
[2] EIP Guidance https://www.epa.gov/sites/default/files/2015-07/documents/eipfin.pdf

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proposed additional 10% reduction in the mass oxides of nitrogen (NOx) Emission Targets in PR 1109.1.

A. U.S. EPA's EIP Guidance does not apply to the B-Cap

As currently drafted, PR 1109.1 at subparagraph (g)(2)(C) includes a 10% reduction (environmental benefit) in Phase I, Phase II, and Phase III Facility BARCT Emission Targets for a Facility that decides to comply with the B-Cap option. MPC understands that the U.S. EPA has not affirmed that the B-Cap is subject to the requirements of U.S. EPA's January 2001 guidance document entitled "Improving Air Quality With Economic Incentive Programs" (EIP Guidance) and is currently evaluating the applicability of the EIP Guidance to the B-Cap.[3] U.S. EPA's EIP Guidance indicates that the B-Cap is not an Economic Incentive Program (EIP). For example, when describing the types of discretionary EIPs, the EIP Guidance includes statements such as the following: 7-1 (cont'd)

- An EIP may be an emission trading program, a financial mechanism program, a program such as a clean air investment fund (CAIF) that has features of both trading and financial mechanism programs, or a public information program.[4]
- The four general types of EIPs are emission trading programs, financial mechanisms, CAIFs, and public information programs.[5]
- Unlike traditional CAA regulatory mechanisms, emission trading involves more than one party.[6]

Since the B-Cap does not involve trading, and clearly does not qualify as any of the other types of EIPs covered by the EIP Guidance, the B-Cap should not be subject to review under the EIP Guidance.

B. U.S. EPA's EIP Guidance allows flexibility for demonstrating environmental benefit

If U.S. EPA, however, ultimately determines that EIP Guidance applies to the B-Cap, the guidance allows flexibility to demonstrate the environmental benefit which can be something other than reducing surplus mass NOx emissions by at least 10%. Indeed, there are already multiple environmental benefits inserted into the B-Cap and I-Plan requirements as we explain below. "Environmental benefit" is defined as follows: 7-2

> *Environmental benefit generally means ... increased or more rapid emission reductions. ... environmental benefit means reducing the amount of surplus emission reductions generated for use in the EIP by at least 10 percent. In addition, environmental benefit can also mean improved administrative mechanisms (e.g., that achieve emissions reductions from sources not readily controllable through traditional regulation), reduced administrative burdens on regulatory agencies that result in increased environmental benefits through other regulatory programs, improved emissions inventories that enhance and lend increased certainty to State planning efforts, and the adoption of emission caps which over time constrain or reduce growth-related emissions beyond traditional regulatory approaches.*

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[3] SCAQMD states in its Draft Staff Report that *"U.S. EPA has initially commented that pursuant to U.S. EPA's January 2001 Improving Air Quality with Economic Incentive Programs, a 10 percent environment benefit will likely be required. Staff is continuing to discuss the elements of the B-Cap with U.S. EPA."* (Draft Staff Report at p. 3-15)

[4] *Id.* at p. 15

[5] *Id.* at p. 18

[5] *Id.* at p. 78

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While the EIP Guidance requires demonstration of environmental benefit, the guidance "recognizes that the type of demonstration appropriate will depend on the goals and characteristics of the EIP [being] implemented."[7]

Furthermore, should the B-Cap be considered as a compliance flexibility trading EIP covered by the EIP Guidance, there are other sections of the EIP Guidance which indicate that the environmental benefit associated with a compliance flexibility trading EIP is not required to be a surplus 10% emission reduction, but may be an alternative demonstration as long as the EIP does not cover a nonattainment area that is needing and lacking an attainment demonstration, known as a "NALD area". As discussed below, South Coast AQMD is not an "NALD area" and therefore has flexibility to allow alternatives.

"NALD areas" are defined as follows:

> *Needing and lacking demonstration (NALD)--means a non-attainment area for which a State is currently required under the CAA to submit an SIP for attainment demonstration, but has not done so.*[8]

The SCAQMD has submitted, and EPA has approved, multiple ozone attainment demonstrations for the South Coast Air Basin, including most recently the 2016 Air Quality Management Plan ("2016 AQMP"), which states as follows:

> *The 2016 AQMP demonstrates how and when the South Coast Air Basin, as well as the Coachella Valley, will attain the ozone and PM2.5 standards as "expeditiously as practicable," but no later than the latest statutory attainment date.*[9]

7-2 (cont'd)

Therefore, the South Coast Air Basin is not a "NALD area" in which an alternative environmental benefit would be prohibited under the EIP Guidance.

Other options for meeting the environmental benefit requirement in the EIP Guidance include the following, some of which are already embedded within the rule framework of the B-Cap and I-Plan as noted in brackets:

- *showing greater or more rapid emission reductions due to trading (e.g., early reductions)* – [The I-Plan for B-Cap Facilities includes a provision for earlier reductions by January 1, 2024 of at least 50% of the total required emission reduction under PR 1109.1 as compared to the schedule for meeting the limits in Tables 1 and 2.]

- *showing other environmental management improvements* – [A Facility that permanently decommissions a Unit and not replacing it with a functionally similar Unit or that reduces its annual throughput or NOx concentration to meet the B-Cap will deliver other important emissions reductions to the South Coast Air Basin beyond NOx, including other criteria pollutants such as VOC, SO_2, and fine particulate matter, as well as benefiting AB-617 communities.]

[7] *Id.* at p. 56
[8] *Id.* At p. 168
[9] 2016 AQMP at p. ES-10

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- *improved administrative mechanisms (for example, your EIP achieves emissions reductions from sources not readily controllable through traditional regulation)*
- *reduced administrative burdens on regulatory agencies that lead to increased environmental benefits through other regulatory programs*
- *improved emissions inventories that enhance and lend increased certainty to State planning efforts*
- *the adoption of emission caps which over time constrain or reduce growth-related emissions beyond traditional regulatory approaches* – [The B-Cap contains restrictions on how new Units are to be added such that a Facility's NOx emissions are less than the Facility's Emission Targets.]
- *for multi-source cap and trade program or a single source cap and trade program, includes a declining cap.* 7-2 (cont'd)

These provisions make clear that alternative environmental benefits are permissible under the EIP Guidance under certain circumstances. Moreover, some of these alternative environmental benefits allowed for under the EIP guidance are already included in the B-Cap and I-Plan as currently drafted, including an accelerated schedule for achieving the majority of the NOx emissions reductions well in advance of what is otherwise required without a B-Cap. Additionally, collateral emissions reductions in other criteria and toxic air pollutants will result from decommissioning and/or reducing the annual utilization or throughput of equipment to meet the B-Cap that improve emissions inventories, represent an emissions cap that constrains or reduces growth-related emissions, and includes a declining cap.

Therefore, if it is ultimately determined by U.S. EPA that the EIP Guidance does indeed apply to the B-Cap, the B-Cap and I-Plan framework for both early emissions reductions as well as collateral pollutant emissions reductions satisfies this environmental benefit obligation as described above. To ensure the rule credits a Facility for these environmental benefits, MPC proposes a new subparagraph (i)(3)(H) and other rule revisions in Attachment 1 of this letter that require a Facility electing to comply with a B-Cap to demonstrate environmental benefit using allowable options in the EIP Guidance.

2. Regulatory certainty is necessary to demonstrate that emission reduction projects will not trigger Federal New Source Review for PM_{10} or $PM_{2.5}$.

As SCAQMD understands, many of the proposed low NOx BARCT limits under PR 1109.1 cannot be achieved without selective catalytic reduction (SCR). MPC and other stakeholders have previously pointed out that installation of SCR may result in increases in emissions of particulate matter less than 10 microns (PM_{10}) and particulate matter less than 2.5 microns ($PM_{2.5}$) (PM_{10} and $PM_{2.5}$ collectively referred to as "fine particulate matter") such that the retrofit project could trigger a "major modification" under U.S. EPA's New Source Review (federal NSR) program, and thus require Best Available Control Technology (BACT).[10] 7-3

[10] See MPC's Fourth Set of Comments on SCAQMD Revised Draft of Proposed Rule 1109.1-Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Industries (Revision Date December 24, 2020) (dated May 12, 2021). MPC previously provided data from emissions testing using reference test methods at a heater with SCR technology to reduce NOx emissions. The resulting emissions factor for fine particulate matter, when combined with the heater input duty and a lower fine particulate matter emissions factor to represent pre-SCR baseline operations, may result in a significant emissions increase subject to the 40 CFR §52.21 and/or SCAQMD 1325 as a major modification.

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In SCAQMD's Preliminary Draft Staff Report for Proposed Amended Rules 1304 and 2005, SCAQMD states:

> *For the purpose of determining federal major NSR applicability, PM and SOx emission increases may be estimated according to the calculations below. The following approach to calcualte [sic] PM and SOx emissions for the purpose of determining NSR applicability has been discussed without opposition with U.S. EPA.*
>
> * * *
>
> *The calculation method will be used in lieu of conducting a source test for PM_{10} emissions when a facility submits a permit application for SCR installation or modification.*

SCAQMD also provides an example calculation for determining the ammonium sulfate as fine particulate matter that may form as a result of installing SCR.[11]

7-3 (cont'd)

For reference, the South Coast Basin is designated in attainment with the PM_{10} NAAQS and is subject to 40 CFR § 52.21 for the Prevention of Significant Deterioration (PSD) permit program. SCAQMD Rule 1325 - Federal $PM_{2.5}$ New Source Review Program – applies to new and modified major sources that trigger the federal NSR threshold for $PM_{2.5}$. Rule 1325 incorporates and adopts U.S. EPA requirements for $PM_{2.5}$, which is designated nonattainment with the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). Nowhere in Rule 1325 has this alternative calculation method been incorporated, referenced, or proposed to be added as part of PR 1109.1. If PR 1109.1 is approved in its current form and the alternative calculation method for determining fine particulate matter is only referenced in SCAQMD's Draft and Final Staff Report and not incorporated into Rule 1325, MPC is concerned that U.S. EPA cannot accept this alternative calculation method and shall require the use of U.S. EPA test methods that are referenced in Rule 1325 to demonstrate that an SCR project has not exceeded the federal major NSR threshold prior to issuance of the permit to construct.

The significance of having a federal major NSR determination for fine particulate matter is the additional amount of time (multiple years) a Facility would need to complete the permitting process as well as potentially requiring BACT for PM_{10} emissions or lowest achievable emission rate (LAER) for $PM_{2.5}$ emissions. In the case of MPC's Los Angeles Refinery, LAER technology for $PM_{2.5}$ could be a fuel gas sulfur treatment project that would add over $100 million in costs. Moreover, this additional cost to comply with PR 1109.1 has not been considered by SCAQMD in the cost-effectiveness of NOx BARCT.

3. Compliance schedules should be dependent on the issuance date of a Permit to Construct, and not on the date of permit application submittal.

Some of the key compliance deadlines in PR 1109.1 for meeting emissions limits and to complete emissions reduction projects are based on a specified duration of time after the Facility submits its Permit to Construct application instead of being based on a time frame after issuance of a Permit to Construct by the SCAQMD. A Facility cannot commence and complete emissions reduction projects for PR 1109.1 without having a Permit to Construct issued by SCAQMD. There are no deadlines or time frames in PR 1109.1 that SCAQMD must meet for issuing a permit after an application has been submitted. As a result, a Facility may not be able to meet a compliance deadline if SCAQMD does not issue an air permit in a timely manner. Based on historical projects, SCAQMD can take several years to issue a Permit to

7-4

[11] SCAQMD, "Preliminary Draft Staff Report, Proposed Amended 1304 - Exemptions, Proposed Amended Rule 2005 – New Source Review for RECLAIM", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/par-1304-and-par-2005/pdsr-par-1304_2005-aug-2021.pdf?sfvrsn=16, pages 2-6 and 2-7

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Construct, and the facility has no certainty when the permit will be ultimately issued. Therefore, any deadlines in PR 1109.1 that are currently in the rule language based on permit application submittal dates should be changed to a time frame after issuance of the permit(s). MPC requests the following deadlines and corresponding language be changed or removed in PR 1109.1:

- Subparagraph (g)(2)(I) contains a compliance date for an approved B-Cap that is *"... no later [than] 54 months from South Coast AQMD Permit Application Submittal Date for all other phases of the selected I- Plan option in Table 6 to meet the Phase I, Phase II, or Phase III Facility BARCT Emission Targets."* Since Table 6 already lists compliance dates that are either a specific date or based on permit issuance, this requirement is unnecessary.

- Paragraph (g)(5) requires a Unit complying with certain emission limits in subdivision (d) and that fails to submit a complete permit application by the specified date in PR 1109.1 to *"... meet the applicable Rule 1109.1 Emission Limits no later than 36 months after the South Coast AQMD permit application submittal date."* This provision is effectively requiring a facility to commence construction on projects necessary to meet PR 1109.1 without a Permit to Construct being issued by SCAQMD if the permit is not issued within a certain time frame, thus potentially forcing non-compliance that is outside the facility's control. Other requirements in PR 1109.1 establish when these limits shall be met following issuance of a Permit to Construct. Those should remain in the case that a complete permit application is not submitted by the specified date in PR 1109.1. Paragraph (g)(5) should be removed in its entirety. 7-4 (cont'd)

Related to the compliance schedule language in subdivision (g), subparagraphs (g)(2)(B) through (G) do not provide a compliance date and are duplicating the required elements in subdivision (i) for Plan submittals. Since subparagraph (g)(2)(A) already references provisions in subdivision (i) and the corresponding compliance date, MPC requests removal of subparagraphs (g)(2)(B) through (G) because they are duplicative and confusing.

4. The compliance date in PR 1109.1 for emission limits with multi-day rolling average periods should be clarified to represent the first day of the rolling average period.

PR 1109.1 contains some emission limits that have multi-day rolling average periods, such as concentration limits on a 7-day rolling average or 365-day rolling average as well as mass emission limits on a 365-day rolling total (i.e., Facility BARCT Emission Target). The compliance date in PR 1109.1 for these longer averaging periods represents the first day of measuring or calculating emissions such that after the last day of the limit's averaging period, the first compliance demonstration is made. For example, Table 6 for I-Plan Option 4 lists a date of January 1, 2024 as the compliance date for meeting the Phase I BARCT Emission Target. The first demonstration of compliance with the tons-per-year BARCT Emission Target will be after December 30, 2024, which is 365 days from January 1, 2024, noting that 2024 is a leap year with 366 days. 7-5

This clarification should be made for all multi-day rolling average periods, and MPC recommends adding a definition in subdivision (c) for "Compliance Date" that reflects this. See Attachment 1 for proposed language to define this term.

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5. The CO limit overlap provision in paragraph (d)(7) should extend to other CO limits PR 1109.1 in addition to those in Tables 1 and 2

Paragraph (d)(7) requires that a carbon monoxide (CO) emission limit established in a SCAQMD Permit to Operate (PTO) for a Unit continue to meet that PTO limit instead of the CO emission limit *"... specified in Table 1 or Table 2."* SCAQMD has established CO limits in other provisions of PR 1109.1 besides those listed in Table 1 and Table 2 that should also be subject to the overlap provision in paragraph (d)(7). Where these CO limits are generally drawn from Table 1 or Table 2 but are not directly referenced, this may lead to confusion on applicability of the CO limit if paragraph (d)(7) does not specify whether the CO limit in a PTO or PR 1109.1 applies. See subparagraphs (d)(3)(A) through (C) and (d)(4)(A) through (C) for CO limits that do not refer directly to Table 1 or Table 2 and thus are not currently covered by the (d)(7) overlap. Also, the interim CO limits in paragraph (f)(1) in Table 4 should be subject to paragraph (d)(7). 7-6

MPC recommends broadening the language in paragraph (d)(7) to clarify that CO emission limits in an applicable PTO limit shall continue to be met in lieu of those in PR 1109.1. See Attachment 1 for proposed revisions to paragraph (d)(7).

Additionally, in regard to CO limits in PR 1109.1, MPC notes the following proposed corrections:

- Paragraph (e)(2) for a B-Cap includes the phrase *"... that elects to meet the NOx and CO emission limits in an approved B-Cap in lieu of meeting Table 1 and Table 2 NOx concentration limits..."*. Under PR 1109.1, a B-Cap is for NOx only and is not also for CO. The term "and CO" must be removed from paragraph (e)(2). This change would make the language consistent with that in paragraph (e)(1) for a B-Plan that does not contain the "and CO" term.

- Paragraph (j)(3) refers to CO emission limits in Table 3. Table 3 does not have CO limits but Table 4 does, so paragraph (j)(3) should instead reference Table 4.

6. Compliance schedule requirements in paragraphs (d)(8) and (d)(9) for Table 1 or Table 2 limits should be incorporated into subdivision (g) (Compliance Schedule) and remove potential conflicts.

Paragraph (d)(8) establishes a schedule to demonstrate compliance with applicable limits in Table 1 or Table 2 that are less than a 365-day averaging period. The schedule is to demonstrate compliance with these limits *"... six months after, either the date the South Coast AQMD Permit to Operate is issued, 36 months after the Permit to Construct is issued or completion of a compliance demonstration source test, whichever is sooner."* However, clauses (g)(1)(B)(i) and (ii) specify different compliance schedules for Table 1 limits, as follows: *"(i) No later than 36 months after a South Coast AQMD Permit to Construct is issued; or (ii) No later than July 1, 2023 if a permit application was not required as specified in subparagraph (g)(1)(A)."* These two schedules conflict and will lead to confusion as to when compliance needs to be demonstrated for Table 1 limits. MPC recommends incorporating paragraphs (d)(8) and (d)(9) as well as other compliance schedule requirements in subdivisions (d) and (e), as applicable, into subdivision (g) titled "Compliance Schedule," such that all compliance schedule requirements are located in one rule subdivision. 7-7

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Relatedly, it is unclear when a permit application is required or is not required under subparagraph (g)(1)(B)(ii). Generally, a permit application will be needed to incorporate the Table 1 limit, but it is unclear when a permit application is not required. MPC requests regulatory clarification on this issue.

Paragraph (d)(9) establishes a compliance schedule for limits with a 365-day rolling average, but this paragraph does not state which limits this schedule applies to. Although MPC presumes this paragraph is intended to address limits in Table 1 or Table 2, as with paragraph (d)(8), SCAQMD needs to clearly state this. Otherwise, this paragraph could be misconstrued as establishing a compliance schedule for a B-Plan or B-Cap, which have 365-day rolling average limits, instead of the schedule specified in paragraph (g)(2) that explicitly addresses the compliance schedule requirements for a B-Plan or B-Cap. See Attachment 1 for proposed revisions to paragraph (d)(9). 7-7 (cont'd)

7. PR 1109.1 sets an inappropriate early shutdown deadline for permanently decommissioned units under the B-Cap.

Clause (e)(2)(D)(i), excerpted below, requires that a Unit scheduled to be permanently decommissioned as part of an approved B-Cap surrender the SCAQMD PTO by specified dates.

> *(i) Surrender the South Coast AQMD Permit to Operate no later than the compliance date for Phase I in I-Plan Option 4 and no later than the permit submittal date for all other phases in an approved I-Plan; ...*

This clause specifies that the "compliance date" for Phase I in I-Plan Option 4 is the permit surrender deadline, but SCAQMD uses a term "permit submittal date" as the deadline for the other I-Plan phases. It is unclear whether "permit submittal date" is referring to a permit application by the Facility, a permit issued by SCAQMD, or some other permit-related action. MPC believes that the permit surrender deadline should not be at any time before the compliance date in Table 6 for all of the I-Plan options in order to provide sufficient time to complete projects that may be important to allow for decommissioning of a Unit prior to the compliance date for an I-Plan phase. MPC recommends simply referring to the listed compliance dates in Table 6. See Attachment 1 for proposed revisions to clause (e)(2)(D)(i). 7-8

Related to this issue, no description exists in PR 1109.1 or the Draft Staff Report for the process to "surrender" a permit. MPC requests additional clarification on the process to surrender or inactivate a PTO for a permanently decommissioned unit.

Finally, clause (e)(2)(D)(iii) reads as if a Unit cannot be sold to a company that is located within the South Coast Air Basin instead of reflecting the intent that the Unit cannot be operated in the South Coast Air Basin. See Attachment 1 for proposed revisions to clause (e)(2)(D)(iii) to reflect this intent.

8. A BARCT B-Cap fully realizes the emission reduction objectives of PR 1109.1, and demonstration with a B-Cap's BARCT Emission Targets is met by monitoring and reporting of the Facility's actual emissions.

The B-Cap is an alternative compliance option provided for under PR 1109.1 that can also achieve the NOx emission reductions. As SCAQMD notes in its August 2021 Preliminary Draft Report for PR 1109.1 and Proposed Rescinded Rule 1109 (Draft Staff Report), *"The B-Cap achieves the same emission reductions as if the facility complied directly with the proposed NOx limits."*[12] MPC supports the 7-9

[12] SCAQMD, "Preliminary Draft Staff Report, Preliminary Draft Proposed Rule 1109.1", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pdsr_pr-1109-1_75_day.pdf?sfvrsn=6, page Ex-1.

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SCAQMD inclusion of the B-Cap option in paragraph (e)(2) of PR 1109.1 to provide an alternative means of demonstrating equivalent cumulative NOx emissions reductions such that the facility may achieve these emissions reductions in a safer and more cost-effective way. However, SCAQMD includes an additional demonstration in the Implementation Compliance Plan (I-Plan) that requires the facility to show that the planned NOx emissions reduction projects in concert with any other strategies to reduce mass emissions will, prospectively, meet the applicable Emission Target. This additional prospective demonstration is summarized as follows:

1. Select an Alternative BARCT NOx Limit on a concentration basis for every unit, which for heaters and boilers must be on a 24-hour rolling average, per subparagraph (e)(2)(B) of the rule. This value cannot exceed the Maximum Alternative BARCT NOx Limits for a B-Cap in Table 3.

2. Accept a permit limit for the Alternative BARCT NOx Limit for every unit, per subparagraph (e)(2)(C) of the rule.

3. Calculate the Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions (B-Cap Annual Emissions) by requiring, in part, the use of the Alternative BARCT NOx Limit per subparagraph (g)(2)(F) and following the calculation method in Attachment B of the rule at Subsection B-6.1. 7-9 (cont'd)

4. Demonstrate in an Implementation Compliance Plan (I-Plan) and B-Cap submittal that the prospective B-Cap Annual Emissions, which incorporates and uses the Alternative BARCT NOx Limit for each unit and other strategies to reduce mass emissions, will not exceed the Emission Targets per subparagraph (g)(2)(G) and by the phased schedule for the chosen I-Plan option. The I-Plan is an additional requirement of the facility that elects to meet a B-Cap. The I-Plan is *"designed to maximize early emissions reductions, where feasible"* to meet each phase of the mass emission targets by deadlines established in Table 6 of PR 1109.1.[13]

The requirement to institute a unit-specific concentration limit such as an Alternative BARCT NOx Limit may be appropriate for the BARCT Equivalent Compliance Plan (B-Plan), which is a separate compliance option from the B-Cap that is based on establishing alternative NOx concentration limits. Conversely, a B-Cap is based on annual mass emissions from the units, which is a function of both the annual average NOx concentration and firing rates of each unit. Instituting a 24-hour average maximum NOx concentration for heaters and other units has no direct coupling to actual sustained emissions, since the 24-hour restricted maximum concentration is based on established worst-case conditions (highest design NOx concentration) that may occur over the course of the normal operating envelope of the emissions unit and control device. MPC's February 1, 2021 comment letter provides details on the inherent variability in NOx concentrations at a heater as well as variable firing rates that materially affect sustained actual emissions. Using a 24-hour maximum concentration to calculate an annual emissions rate for every unit will, by itself, result in a vastly unrealistic overestimate of the facility's future emissions.

For this reason, the Alternative BARCT NOx Limit should not be used solely to calculate the B-Cap Annual Emissions as other variables are important to calculate emissions. The calculation method for the facility's B-Cap Annual Emissions in Attachment B at Subsection B-6.1, excerpted below, allows the incorporation of "emissions reductions from reduced throughput, efficiency, reduced capacity, and any

[13] SCAQMD, "Preliminary Draft Staff Report, Preliminary Draft Proposed Rule 1109.1", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pdsr_pr-1109-1_75_day.pdf?sfvrsn=6, page Ex-1

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other strategy to reduce mass emissions." A facility should not be penalized for operating at NOx concentration levels that are lower than the 24-hour Alternative BARCT NOx Limit at its heaters and other units when it is able to practically do so and when operating conditions allow. This and other related strategies to reduce annual NOx emissions is an important and necessary element of the B-Cap Annual Emissions calculation that would be considered in the "(Throughput or Other Reductions)" aspect of the equation.

$$\text{Phase I BARCT B} - \text{Cap Annual Emissions}_{B-Cap} = \sum_{i=1}^{N}\left(\frac{C_{\text{Phase I Alternative BARCT Emission Limit}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions}\right)_i + (0_{\text{Decommissioned Units}})_i - (\text{Throughput or Other Reductions})$$

7-9 (cont'd)

Where:

N = Number of included units in B-Cap under Phase I

$C_{\text{Phase I Alternative BARCT Emission Limit}}$ = The applicable Alternative BARCT NOx Limit in an approved B-Cap for unit i included in the B-Cap

C_{Baseline} = Representative NOx Concentration as defined in subdivision (c) for unit i included in the B-Cap

Baseline Unit Emissions = Baseline Unit Emissions as defined in subdivision (c) and for unit i included in the B-Cap

Throughput or Other Reductions = Emission reductions occurred from other than reducing the concentration limit.

For planning purposes in the B-Cap submittal, an appropriate and representative calculation of B-Cap Annual Emissions is based on the firing rate and concentration of each unit that incorporates emissions reductions projects and other strategies to reduce mass emissions. This basic demonstration of future emissions scenario(s) is not the means for which compliance with the Emission Targets is ultimately met, but rather it serves as a means of SCAQMD reviewing and approving the B-Cap and I-Plan for implementation. Compliance with the B-Cap as a practical matter is a matter of the facility showing that its actual NOx emissions are less than the applicable Emission Targets. MPC requests that the SCAQMD document their agreement that the "(Throughput or Other Reductions)" aspect of the equation above can include a variety of different means to achieve the Emission Targets, including operating at lower annual-average emissions levels.

9. The 24-hour rolling average associated with PR 1109.1 NOx concentration limits for boilers and process heaters is not reasonable as it is not representative of inherent operational variability associated these units.

7-10

Maximum NOx concentration limits are established in PR 1109.1 for boilers and process heaters on a 24-hour rolling average. These limits and the associated short-term averaging period are not proven and/or are infeasible for some refinery heaters. Burner manufacturers generally base their NOx emissions specifications and guarantees on set operating conditions, including combustion air temperature, fuel gas composition, and excess air going to the burner(s). Refineries have dynamic operating conditions and it is

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common for process heaters to run at a wide operating envelope that deviate from the ideal set of conditions that are used for burner NOx concentration specifications.

Over a longer averaging period like a 365-day rolling average, the heater's operating conditions may more closely align with those presumed by the burner manufacturer in establishing the NOx emissions guarantee, but a 24-hour rolling average limit may not always be met when there are hydrogen and other compositional and heating value fluctuations in refinery fuel gas, changes in oxygen content within the heater, or other real-world variabilities in operating conditions that can cause the NOx concentration to increase above the limit in the short-term. MPC proposes that the averaging period for NOx concentration limits at boilers and process heaters be changed from 24-hour rolling average to 365-day rolling average. 7-10 (cont'd)

10. SCAQMD's approval process for an I-Plan, B-Plan, and B-Cap should be granted to the Facility if the information described in paragraph (i)(4) is provided.

Paragraph (i)(4) and its references to paragraphs (i)(1) through (3) contain the prescriptive informational elements for the Facility to provide in an I-Plan, B-Plan, or B-Cap to be approved by SCAQMD. Paragraph (i)(4) provides for SCAQMD to approve or disapprove the I-Plan, B-Plan, or B-Cap based on whether the owner or operator demonstrates that certain requirements have been met. In general, the information required in these plans are prescriptive in nature, consisting of data and calculations, such that SCAQMD should not disapprove a Plan submittal if it contains this information. However, per subparagraph (i)(4)(C), the Facility gets only one opportunity to correct any deficiencies and re-submit a Plan, and then if SCAQMD disapproves the Plan, the Facility must comply with the schedule in paragraph (g)(1) which excludes the alternative compliance demonstration of a B-Plan or B-Cap. This mandatory and stringent off-ramp from a B-Plan or B-Cap to instead meet the Table 1 limits is unworkable to a Facility that has made long-term plans to meet one of these alternative compliance methods. MPC proposes changes to paragraph (i)(4) in Attachment 1 of this letter that: 7-11

- Provides SCAQMD 30 days to conduct an initial administrative completeness review of the Plan(s);
- Clarifies SCAQMD shall not disapprove a Plan if the Facility provides the required information in the rule;
- Removes the mandatory off-ramp for a Facility to meet the compliance schedule in paragraph (g)(1) instead of (g)(2); and
- Subjects an I-Plan, B-Plan, or B-Cap to Rule 221 – Plans.

MPC has also included in Attachment 1 of this letter proposed corrections and updates to subdivision (i) to address other updates, as summarized below:

- New subparagraphs (i)(1)(A), (i)(2)(A), and (i)(3)(A) are introduced to clarify if multiple Facilities are covered in a single I-Plan, B-Plan, and B-Cap due to being under the same ownership.
- Subparagraphs (i)(1) and (i)(3) should reference the BARCT Equivalent Mass Emissions Cap for the B-Cap instead of the Alternative NOx BARCT Limit for a B-Plan as the key approach to address equivalent emissions reductions under PR 1109.1.

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- Subparagraph (i)(1)(D) is duplicative of subparagraph (i)(1)(F) and should be removed.

- Subparagraph (i)(1)(F) references the wrong citation for specification of the I-Plan option, so this reference has been updated.

- Subparagraph (i)(3)(D), shown as subparagraph (i)(3)(E) in Attachment 1 of this letter, restricts reductions in mass emissions to those only associated with a reduction in throughput, but Attachment B at Section B-6 allows for other reductions to be incorporated into the BARCT Annual Emissions calculation. The language in this subparagraph is updated to be consistent with Section B-6. 7-11 (cont'd)

- Subparagraph (i)(3)(E), shown as subparagraph (i)(3)(F) in Attachment 1 of this letter, incorrectly references the term "BARCT Equivalent Mass Emissions" for a B-Plan instead of the term "BARCT B-Cap Annual Emissions" for a B-Cap.

- Subparagraph (i)(4)(B), shown as subparagraph (i)(4)(D) in Attachment 1 of this letter, allows only 30 days for a Facility to correct deficiencies and resubmit a Plan. MPC requests the more reasonable 60 days instead of 30 days in the event that the deficiencies noted by SCAQMD require additional time to develop new information and prepare a resubmittal.

- Clause (i)(5)(C)(iv) requires a modification to the Plan if an emission reduction project is moved to a different implementation phase or is removed from a phase. The compulsory information required in subparagraph (i)(1) through (4) does not include the time frame for emission reduction projects, so it should not be a criterion for requiring a modification to the Plan. The permitting process is a more appropriate means of addressing changes that involve emission reduction projects.

11. The interim limit for a B-Cap in paragraph (f)(3) requires additional specificity on the compliance time frame.

Paragraph (f)(3), excerpted below, establishes a requirement to maintain emissions in aggregate below the Baseline Facility Emissions.

> *"(3) An owner or operator of a Former RECLAIM Facility that elects to comply with an approved B-Cap shall not operate any unit included in the approved B-Cap unless the NOx emissions for all units in the B-Cap are in aggregate at or below the Baseline Facility Emission."* 7-12

MPC requests that SCAQMD clarify the compliance demonstration elements of this rule provision, specifically to: (1) identify the compliance date (also see item 6 regarding compliance dates), (2) stipulate the averaging period (i.e., 365-day rolling average), and (3) clarify when the interim limit is no longer applicable.

12. Certain provisions for time extension requests in subdivision (h) should be adjusted to support timely approvals.

Time extensions for an approved I-Plan may be requested per paragraph (h)(2) under certain listed criteria. MPC requests the following changes that will allow for an improved process to qualify for and be granted time extensions: 7-13

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- Clause (h)(2)(C)(i) allows an owner or operator to apply for a time extension if it took 24 months for SCAQMD to issue a permit after submittal of a permit application. MPC requests that this time frame be changed from 24 to 18 months to provide a more reasonable permitting time frame for projects needed to meet PR 1109.1.

- Paragraph (h)(4) allows SCAQMD 60 days to act on a time extension request. MPC requests that this time frame be changed to 30 days in order to provide sufficient time for an owner or operator to respond to any deficiencies noted by SCAQMD in a Plan submittal before a compliance deadline. 7-13 (cont'd)

- Paragraph (h)(7) lists two deadlines for a Facility to meet emission limits if a time extension is disapproved. MPC proposes to add the phrase "whichever is later" at the end to provide certainty on the applicable deadline.

13. Key averaging time and testing schedule requirements in the emissions testing provisions need to be revised.

MPC offers the following proposed changes to address concerns with the testing provisions in subdivision (k).

- MPC proposes a new subparagraph to address the potential conflict between the source test requirements in Tables 7 and 8 of PR 1109.1 and those in a SCAQMD PTO. See Attachment 1 for new paragraph (k)(3).

- The source test protocol for paragraph (k)(7) requires *"an averaging time of at least 2 hours."* The Draft Staff Report at page 3-23 states that the averaging time is *"no less than 15 minutes but no longer than 2 hours."* MPC proposes to change the language in subparagraphs (k)(7)(A) and (B) to that shown as subparagraphs (k)(8)(A) and (B) in Attachment 1 of this letter, which reflects the draft staff report. 7-14

- The timing in subparagraph (k)(7)(A) to submit a source test protocol relative to receiving a Permit to Construct may not be possible, because the Facility may not have sufficient detailed information for a complete protocol if the Unit is still being designed. Similarly, the timing in subparagraph (k)(7)(C) to conduct a source test within 90 days upon approval of the source test protocol may not be possible, because the air pollution control equipment may not be installed and fully operational by that time. To address this, MPC proposes that the source test protocol timing is a function of the source test itself in order to ensure that the unit is operational (e.g., that it has resumed stable operations after completion of an emission reduction project) and is ready for testing. See Attachment 1 for revisions to subparagraphs (k)(7)(A) and (B) which are shown as subparagraphs (k)(8)(A) and (B) in Attachment 1 of this letter.

- MPC proposes to change the deadline for submitting a source test report in paragraph (k)(11) from 60 to 90 days of completion of the source test. Due to the increased number of source testing obligations pursuant to PR 1109.1 and the fact that meeting this requirement is primarily a function of the contracted and SCAQMD-approved source testing firm, an additional 30 days is needed to address the increased workload and potential delays in reporting by a source testing firm.

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14. The provision to limit the total amount of NOx emission reductions from decommissioned units to 15% under a B-Cap new unit exemption is unreasonably low.

Subparagraph (e)(2)(F) contains restrictions on adding a new unit under the B-Cap. Of particular concern is clause (e)(2)(F)(iv) that restricts the total amount of NOx reductions from decommissioned units to 15 percent of the Final Phase Facility BARCT Emission Target. From the Draft Staff Report, it appears that this clause is attempting to address SCAQMD's concerns with a unit being replaced with a "functionally similar unit outside the B-Cap".[14] To address this concern, MPC proposes to revise the clause to address units that are decommissioned but not replaced with a functionally similar Unit. Accordingly, this will appropriately delineate between projects that are being completed to satisfy environmental rule obligations and unit replacements. With this restriction in place, MPC believes that the 15% threshold should be higher and it should be based on the Total Facility NOx Emissions Reductions, and not the Final Phase BARCT Emission Target, which compares emission reductions for decommissioned units to total reductions. See Attachment 1 for a proposed revision to clause (e)(2)(F)(iv). 7-15

Relatedly, MPC notes that clause (e)(2)(F)(i) refers to *"Equivalent Mass Emission"* instead of *"B-Cap Annual Emissions."* The former term is for a B-Plan and is not applicable to a B-Cap. MPC has updated this clause in Attachment 1 of this letter.

15. The future established NOx limits for small refinery boilers and heaters is not based on BARCT.

SCAQMD includes 5 ppmv and 9 ppmv NOx limits for small refinery boilers and heaters, respectively, at subparagraphs (d)(3)(C) and (d)(4)(C), that take effect in the future. These limits are not based on a current technology that is safe, technically feasible, and cost-effective, which are compulsory elements of a control technology to be considered for BARCT. Instead, SCAQMD states that the limits are based on emerging technologies and that staff *"... will monitor the development of emerging technologies and will include in the Resolution a commitment to report on the status of the emerging technologies in 2029 and conduct a technology assessment if these technologies are not being commercialized."*[15] It is practically impossible to know if a technology will be technically feasible, safe to operate, and cost-effective for small refinery boilers and heaters ten years from now or even further into the future. By establishing such limits in this rulemaking, it goes against the Health & Safety Code that requires technical feasibility and cost effectiveness be demonstrated in order for a control technology to be BARCT. 7-16

MPC believes these future limits that are not based on BARCT should be removed from the rule. At the least, MPC recommends that SCAQMD make the future effective date of these limits dependent on the results of SCAQMD's status report in 2029 that addresses whether or not these emerging technologies are technically feasible and cost-effective for BARCT as of 2029 or later.

16. Potential confusion between the RECLAIM transition and B-Cap related limits and associated calculation and monitoring methods needs to be addressed in the rule.

MPC requests clarity as to when a Facility is operating after the effective date of PR 1109.1 but before it becomes a Former RECLAIM Petroleum Refinery. Specifically, PR 429.1 addresses startup and shutdown emissions for PR 1109.1 but only applies to a Former RECLAIM Petroleum Refinery. Until a 7-17

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[14] SCAQMD, "Preliminary Draft Staff Report: Preliminary Draft Proposed Rule 1109.1", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pdsr_pr-1109-1_75_day.pdf?sfvrsn=6, page 3-10

[15] SCAQMD, "Preliminary Draft Staff Report: Preliminary Draft Proposed Rule 1109.1", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pdsr_pr-1109-1_75_day.pdf?sfvrsn=6, page 3-6

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Final Determination Notification is issued, it is unclear how a Facility is to address applicable limits that may be in effect for PR 1109.1. Relatedly, compliance with Rules 218.2 and 218.3 for CEMS is not required until a Facility becomes a Former RECLAIM Petroleum Refinery. For any limits in effect under PR 1109.1 at the Facility until it receives a Final Determination Notification, it is unclear if the Facility should follow a different set of CEMS requirements. MPC requests regulatory certainty to address the transition between RECLAIM and PR 1109.1 for compliance monitoring. 7-17 (cont'd)

17. PR 1109.1 contains other clerical and administrative errors that need to be corrected.

Attachment 1 is a mark-up of PR 1109.1 with proposed changes as described in this letter and as follows:

- The rolling average times in Table 3 that are shown as "24-day" should be "24-hour."
- Capitalize words such as "Unit," "Petroleum Refinery," "Facility," etc., consistently throughout the rule to refer to the term defined in subdivision (c).
- Add in missing words for correct syntax. 7-18

Note that Attachment 1 of this letter is a conversion of the Adobe PDF version of PR 1109.1 into Microsoft Word, so the formatting of Attachment 1 is not as exact as shown in the August 20, 2021 version on SCAQMD's website.

For additional clarity, MPC recommends that SCAQMD add rule definitions for acronyms and shortened terms used in the rule such as "BARCT," "RECLAIM," and "O_2." MPC has not included proposed definitions for these terms in Attachment 1.

18. PR 1109.1 needs to reference and incorporate the startup and shutdown provisions in PR 429.1 and revise PR 429.1 so as to appropriately address management of startups and shutdowns.

The proposed PR 1109.1 rule does not reference PR 429.1 or otherwise clarify how startup and shutdown emissions are to be included or excluded for accounting against emission limits. Particularly, PR 1109.1 needs to expressly state that emissions from startups and shutdowns are exempt when determining compliance with the Alternative NOx BARCT Limits and the annual mass emissions against the BARCT Emissions Targets. To remove this ambiguity, MPC requests SCAQMD add a reference or statement in PR 1109.1 excluding the emissions from startup and shutdown events in PR 429.1 for purposes of compliance with emission limits in PR 1109.1. 7-19

Regarding the proposed PR 429.1 rule itself, MPC offers the following comments to address multiple startup and shutdown activities that are required for compliance with PR 1109.1. Attachment 2 of this letter is a proposed mark-up of PR 429.1 to reflect MPC's comments.

A. <u>Cogeneration unit electrical testing</u>

Cogeneration units are subject to industry and electrical standards to ensure that the equipment is reliable and in good working order. This includes conducting electrical testing following any upgrades or repairs made to the cogeneration unit's safety and control systems (e.g., protection relay and excitation control systems). These tests are to ensure that the systems have been functionally tested to prevent process safety and reliability issues. Some testing must take place at different electrical loads that can only occur during the startup phase. The testing duration ranges from 4 to 12 hours depending on the complexity of the 7-20

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testing. As this testing is to ensure the safety and reliability of the system, MPC requests that this testing be categorically excluded from the time limitations in paragraph (d)(2) of PR 429.1 by including the following: 7-20 (cont'd)

- Add the following exemption as a new subparagraph (g)(1)(E) to paragraph (g)(1): *"electrical testing associated with commissioning of cogeneration control systems following upgrades or repairs."*; and

- Copy the definition of gas turbine from subdivision (c) of PR 1109.1, which incorporates the term "cogeneration."

B. Catalyst maintenance and related activities

MPC offers the following proposed changes to address catalyst maintenance and related activities:

- Paragraph (c)(2) requires that catalyst maintenance for a Unit *"... which has a bypass stack or duct ..."* MPC requests removal of this phrase, since some combustion units have only one stack which is used for both normal operations and for catalyst maintenance activities that bypass the control equipment (i.e., the control equipment is not operable during control equipment maintenance). Paragraph (d)(8) is also revised to align with this definition.

- The proposed definition in paragraph (c)(2) is specific only to catalyst maintenance activities and is not inclusive of other maintenance activities inherently needed for NOx post-combustion control equipment. For example, routine maintenance activities associated with a post-combustion control equipment's ammonia injection system and related components is required, which would impact emissions because ammonia is not being introduced into the control equipment during that time. MPC proposes to revise this definition to include maintenance of ancillary components in NOx post-combustion control equipment. 7-21

- Paragraph (d)(7) is an operating requirement for post-combustion control equipment if the temperature of the exhaust gas to the inlet of the control equipment *"... is greater than or equal to the minimum operating temperature."* Operating temperature fluctuates during startup, and MPC has observed from its operations that the minimum temperature may be initially reached for a very short duration and then fall below that minimum temperature before again rising to a minimum temperature until the stabilized minimum temperature is reached. For this reason, MPC requests that the aforementioned phrase be changed to *"... is greater than or equal to the minimum operating and stable temperature."*

- Subparagraph (d)(8)(D) requires documentation from a manufacturer of the *"minimum safe operating rate for the unit being bypassed."* The minimum safe operating rate for a Unit is a function of process safety management reviews by operations and safety staff and the application of MPC's operational safety policies and procedures to a Unit. Manufacturers will not know or have documentation of the minimum safe operating rate for a Unit. MPC requests deletion of this subparagraph.

C. Gas turbines with NOx post-combustion control equipment

Gas turbines with NOx post-combustion control equipment have issues that are similar to boilers and process heaters with respect to the necessary time allowance to meet NOx emission limits. MPC requests 7-22

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that Table 1 of PR 429.1 be changed such that a gas turbine with NOx post-combustion control equipment is subject to the same 48-hour time allowance as boiler and process heaters with NOx post-combustion control equipment. 7-22 (cont'd)

D. Two-hour duration limit in Table 1 for process heaters

Based upon a review of its procedures and practices, MPC has determined that the startup and shutdown duration limit of two hours in Table 1 is insufficient for process heaters. It is unclear in the corresponding Draft Staff Report how this hourly limit was established. From MPC's experience it is unrealistic for several process heaters that do not have post-combustion NOx control equipment to reach stable conditions in two hours such that the NOx emissions controls (i.e., ultra-low NOx burners) can effectively meet the emission limits in PR 1109.1. For example, some heaters inherently require slower warming to avoid damaging downstream equipment affected by temperature changes and thus need more than 2 hours to start up. Also, heaters with natural draft systems or several dozen burners that need to be lit during startup will make control of excess oxygen difficult at low and fluctuating firing rates, which causes higher NOx concentrations until stable conditions are reached. To ensure MPC is allotted sufficient time to allow for safe and steady startup, MPC requests additional consultation with SCAQMD to support an appropriate increase to the 2-hour duration limit currently proposed in Table 1 for process heaters. 7-23

19. PR 1304 should further clarify in the rule language that BACT exemption is allowed for equipment replacements across categories of equipment.

MPC appreciates SCAQMD's consideration for including a limited exemption from BACT requirements for PM_{10} and SO_X emissions from projects that are implemented to comply with the PR 1109.1 requirements. This is important for allowing projects that will be completed for PR 1109.1 compliance to be permitted efficiently and implemented in a cost-effective manner. While the language in PR 1304(f)(1)(B) appears to allow for the exemption to apply to equipment to be replaced with other equipment across different source categories, there are some references in the associated PR 1304 Draft Staff Report indicating that equipment can only be replaced within the same source category (e.g., boilers replacing boilers).[16] For projects that involve replacement of equipment across source categories (e.g., boilers replacing co-generation units) that is functionally similar and does not increase the cumulative total maximum rated capacity, the rule language and staff report should be updated to reflect that the limited BACT exemption in PR 1304(f)(1) can be used. MPC has provided suggested rule language changes in Attachment 1 of this letter. 7-24

20. PR 1304 (f)(1)(B) should allow for a longer period for replaced equipment to be operated at the same time consistent with federal requirements

Subparagraph (f)(1)(B) of PR 1304 currently states that *"For the new and/or modified permit unit(s) and the permit unit(s) being replaced, a maximum of 90 days is allowed as a startup period for simultaneous operation."* The length of time allowed for simultaneous operation of replacement units should be adjusted to align with the requirements of 40 CFR § 51.165(a)(1)(vi)(F) which allows a 180-day transition period for replacement units. This is a more appropriate time period when units are being replaced. PR 1304(f)(1)(B) should be adjusted to align with 40 CFR § 51.165(a)(1)(vi)(F). 7-25

[16] SCAQMD, "Preliminary Draft Staff Report, Proposed Amended 1304 – Exemptions, Proposed Amended Rule 2005 – New Source Review for RECLAIM" http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/par-1304-and-par-2005/pdsr-par-1304_2005-aug-2021.pdf?sfvrsn=16 page 2-2

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Conclusion

MPC provides these comments to the Preliminary Draft Proposed Rule 1109.1 and related proposed and proposed amended rules issued August 20, 2021 to address critical deficiencies and needed clarifications. 7-26

Please note that in submitting this letter, MPC reserves the right to supplement its comments as it deems necessary, especially if additional or different information is made available to the public regarding the Proposed Rule 1109.1 rulemaking process.

Thank you for the opportunity to provide comments. We are glad to discuss further and look forward to continued dialogue.

Sincerely,

Bradley J. Levi

Brad Levi
Vice President – Los Angeles Refinery

Attachments

cc: ***SCAQMD***
Sarah Rees – Deputy Executive Officer
Susan Nakamura – Assistant Deputy Executive Officer
Michael Krause – Planning and Rules Manager

cc: ***SCAQMD Governing Board***
Hon. Ben Benoit – Governing Board Chair
Hon. Lisa Bartlett – Governing Board Member
Hon. Joe Buscaino – Governing Board Member
Hon. Michael Cacciotti – Governing Board Member
Hon. Vanessa Delgado – Governing Board Vice-Chair
Hon. Gideon Kracov – Governing Board Member
Hon. Sheila Kuehl – Governing Board Member
Hon. Larry McCallon – Governing Board Member
Hon. Veronica Padilla-Campos – Governing Board Member
Hon. V. Manuel Perez – Governing Board Member
Hon. Rex Richardson – Governing Board Member
Hon. Carlos Rodriguez – Governing Board Member
Hon. Janice Rutherford – Governing Board Member

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ecc: 2021-09-17 MPC 75 Day Comment Letter on Revised Draft of SCAQMD PR 1109.1
Ruth Cade, MPC RE
Chris Drechsel, MPC RE
Denis Kurt, MPC LAR
Robert Nguyen, MPC LAR
Robin Schott, MPC LAR
Vanessa Vail, MPC LAW
Ben Franz, MPC LAW

Attachment 1

Proposed changes to PR 1109.1 (August 20, 2021 version)

Preliminary Draft Rule

(Adopted TBD)
Revision Date 8-20-21

PROPOSED RULE 1109.1. EMISSIONS OF OXIDES OF NITROGEN FROM PETROLEUM REFINERIES AND RELATED OPERATIONS

(a) Purpose

The purpose of this rule is to reduce emissions of oxides of nitrogen (NOx), while not increasing carbon monoxide (CO) emissions, from ~~units~~Units at ~~petroleum refineries~~a Petroleum Refineries and ~~facilities~~Facilities with ~~related operations~~Related Operations to ~~petroleum refineries~~Petroleum Refineries.

(b) Applicability

The provisions of this rule shall apply to an owner or operator of ~~units~~Units at ~~petroleum refineries~~Petroleum Refineries and ~~facilities~~Facilities with ~~related operations~~Related Operations to ~~petroleum refineries~~Petroleum Refineries.

(c) Definitions

(1) ALTERNATIVE BARCT NOx LIMIT FOR PHASE I, PHASE II, ~~OR~~AND PHASE III means the ~~unit~~Unit specific NOx concentration limit that is selected by the owner or operator of a Facility to achieve the Phase I, Phase II, or Phase III Facility BARCT Emission Target in the aggregate in the B-Plan or B-Cap, where the NOx concentration limit will include the corresponding percent O_2 correction and determined based on the averaging time in Table 1 or subdivision (k), whichever is applicable. ~~subdivision (k), whichever is applicable.~~

(2) ASPHALT PLANT means a ~~facility~~Facility that processes crude oil into asphalt.

(3) BASELINE FACILITY EMISSIONS means the sum of all the Baseline Unit Emissions at a Facility as calculated according to Attachment B of this rule.

(4) BASELINE UNIT EMISSIONS means a Unit's emissions as reported in the 2017 NOx Annual Emissions Report, or another representative year, as approved by the Executive Officer.

(5) BARCT EQUIVALENT COMPLIANCE PLAN (B-PLAN) means a compliance plan that allows an owner or operator to select NOx concentration limits for all Units subject to this rule that are equivalent, in aggregate, to the NOx concentration limits specified in Table 1 and Table 2.

(6) BARCT EQUIVALENT MASS CAP PLAN (B-CAP) means a compliance

PR 1109.1 - 1

Preliminary Draft Rule

plan that establishes a mass emission cap for all ~~units~~Units subject to this rule

PR 1109.1 - 2

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

that, in aggregate, are equivalent to or less than the Final Phase Facility BARCT Emission Target.

(7) BIOFUEL PLANT means a Facility that produces fuel by processing feedstocks including vegetable oil, animal fats, and tallow.

(8) BOILER means any Unit that is fired with gaseous fuel and used to produce steam. For the purpose of this rule, boiler does not include CO boilers.

(9) CO BOILER means a boiler with an integral waste heat recovery system used to oxidize CO-rich waste gases generated by the FCCU.

(10) COMPLIANCE DATE means the date at which the Facility shall begin to quantify emissions as required by this rule. The first period for compliance with an applicable emissions limit occurs after the date following the compliance date and the averaging period of the limit.

~~(10)~~(11) CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) is as defined by Rule 218 – Continuous Emission Monitoring.

~~(11)~~(12) DUCT BURNER means a device in the heat recovery steam generator of a Gas Turbine that combusts fuel and adds heat energy to the gas turbine exhaust.

~~(12)~~(13) FACILITIES WITH RELATED OPERATIONS TO PETROLEUM REFINERIES includes Asphalt Plants, Biofuel Plants, Hydrogen Production Plants, ~~petroleum coke calcining facilities~~Petroleum Coke Calcining Facilities, Sulfuric Acid Plants, and Sulfur Recovery Plants.

~~(13)~~(14) FACILITIES WITH THE SAME OWNERSHIP means Facilities and their subsidiaries, Facilities that share the same board of directors, or Facilities that share the same parent corporation.

~~(14)~~(15) FACILITY or FACILITIES means, for the purpose of this rule, any ~~unit~~Unit or group of ~~units~~Units which are located on one or more contiguous properties, in actual physical contact or separated solely by a public roadway or other public right-of--way, and operate under one South Coast AQMD Facility ID or Facilities with the Same Ownership.

~~(15)~~(16) FINAL DETERMINATION NOTIFICATION means the notification issued by the Executive Officer to a RECLAIM ~~facility~~Facility designating that the ~~facility~~Facility is no longer in the NOx RECLAIM program.

~~(16)~~(17) FINAL PHASE FACILITY BARCT EMISSION TARGET means the total mass emissions remaining per Facility calculated based on the applicable Table 1 emission limits or Table 2 conditional emission limits and the Baseline Facility Emissions.

~~(17)~~(18) FLARE means, for the purpose of this rule, a combustion device that

PR 1109.1 - 2

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

oxidizes combustible gases or vapors from tank farms or liquid unloading, where the combustible gases or vapors being destroyed are routed directly

PR 1109.1 - 3

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

into the burner without energy recovery, and that is not subject to Rule 1118 – Control of Emissions from Refinery Flares.

~~(18)~~(19) FLUIDIZED CATALYTIC CRACKING UNIT (FCCU) means a Unit in which petroleum intermediate feedstock is charged and fractured into smaller molecules in the presence of a catalyst; or reacts with a contact material to improve feedstock quality for additional processing; and the catalyst or contact material is regenerated by burning off coke and other deposits. The FCCU includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat including a CO boiler.

~~(19)~~(20) FORMER RECLAIM FACILITY means a Facility, ~~or any of~~including its successors, that was in the NOx Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX, that has received a Final Determination Notification, and is no longer in the NOx RECLAIM program.

~~(20)~~(21) FUNCTIONALLY SIMILAR means, for the purpose of this rule, a Unit that will perform the same purpose as a Unit that was permanently decommissioned in an approved B-Cap.

~~(21)~~(22) GAS TURBINE means an internal-combustion engine in which the expanding combustion gases drive a turbine which then drives a generator to produce electricity. Gas Turbines can be equipped with a cogeneration gas turbine that recovers heat from the Gas Turbine exhaust and can include a Duct Burner.

~~(22)~~(23) HEAT INPUT means the heat of combustion released by burning a fuel source, using the Higher Heating Value of the fuel. This does not include the enthalpy of incoming combustion air.

~~(23)~~(24) HIGHER HEATING VALUE (HHV) means the total heat liberated per mass of fuel combusted expressed as British thermal ~~units~~Units (Btu) per pound or cubic feet when fuel and dry air at standard conditions undergo complete combustion and all resulting products are brought to their standard states at standard conditions.

~~(24)~~(25) HYDROGEN PRODUCTION PLANT means a Facility that produces hydrogen by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes which primarily supplies hydrogen for petroleum refineries and Facilities with Related Operations to Petroleum Refineries.

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(25)~~(26) IMPLEMENTATION COMPLIANCE PLAN (I-PLAN) means an implementation plan for Facilities with six or more Units that includes an alternative implementation schedule and alternative emission reduction targets.

~~(26)~~(27) I-PLAN PERCENT REDUCTION TARGET means the percent reduction target specified for each phase of an I-Plan as specified in Table 6.

~~(27)~~(28) NATURAL GAS means a mixture of gaseous hydrocarbons, with at least 80 percent methane (by volume), and of pipeline quality, such as the gas sold or distributed by any utility company regulated by the California Public Utilities Commission.

~~(28)~~(29) NEW UNIT means, for the purpose of this rule, any Unit that meets the applicability of subdivision (b) where the South Coast AQMD Permit to Construct is issued on or after [*DATE OF ADOPTION*].

~~(29)~~(30) OXIDES OF NITROGEN (NOx) EMISSIONS means the sum of nitric oxide and nitrogen dioxide emitted in the flue gas, calculated, and expressed as nitrogen dioxide.

~~(30)~~(31) PARTS PER MILLION BY VOLUME (ppmv) means, for the purpose of this rule, milligram of pollutant per liter of dry combustion exhaust gas at standard conditions.

~~(31)~~(32) PETROLEUM COKE CALCINER means a Unit used to drive off contaminants from green petroleum coke by bringing the coke into contact with heated gas for the purpose of thermal processing. The Petroleum Coke Calciner includes, but is not limited to, a kiln, which is a refractory lined cylindrical device that rotates on its own axis, and a pyroscrubber, which combusts large carbon particles in a stream of waste gas.

~~(32)~~(33) PETROLEUM COKE CALCINING FACILITY means a Unit within a Petroleum Refinery, or as a separate Facility, that operates a ~~petroleum coke calciner~~Petroleum Coke Calciner.

~~(33)~~(34) PETROLEUM REFINERY means a Facility identified by the North American Industry Classification System Code 324110, Petroleum Refineries.

~~(34)~~(35) PHASE I, PHASE III, OR PHASE III BARCT B-CAP ANNUAL EMISSIONS means the total NOx mass emissions remaining per Facility that incorporates BARCT Alternative NOx Limits for Phase I, Phase II, and Phase III, permanently decommissioned ~~units~~Units, and other emission reduction strategies to meet the respective Phase I, Phase II, or Phase III Facility BARCT Emission

PR 1109.1 - 5

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

Targets in an I-Plan and are calculated pursuant to Attachment B of this rule.

~~(35)~~(36) PHASE I, PHASE II, OR PHASE III BARCT EQUIVALENT MASS EMISSIONS means the total NOx mass emissions remaining per Facility that incorporates respective BARCT Alternative NOx Limits for Phase I, Phase II, and Phase III in an approved B-Plan that are designed to meet the respective Phase I, Phase II, or Phase III Facility BARCT Emission Targets in an I-Plan and are calculated pursuant to Attachment B of this rule.

~~(36)~~(37) PHASE I, PHASE II, OR PHASE III FACILITY BARCT EMISSION TARGET means the total NOx mass emissions per Facility that must be achieved in an approved B-Plan or B-Cap that are based on the percent reduction target of Phase I, Phase II, or if applicable, Phase III of an I-Plan option in Table 6 and are calculated pursuant to Attachment B of this rule.

~~(37)~~(38) PROCESS HEATER means any Unit fired with gaseous and/or liquid fuels which transfers heat from combusted gases to water or process streams.

~~(38)~~(39) RATED HEAT INPUT CAPACITY means the maximum heat input capacity, which is the total heat of combustion released by burning a fuel source, as specified by the South Coast AQMD permit.

~~(39)~~(40) REPRESENTATIVE NOx CONCENTRATION means the most representative NOx emissions in the exhaust of the Unit as approved by the Executive Officer and measured by a certified CEMS if the Unit operates with a certified CEMS or the most recent approved source test for ~~units~~Units not operating a certified CEMS. The Representative NOx Concentration for ~~units~~Units that do not have CEMS or source test emission data will be based on the South Coast AQMD Annual Emission Report default emission factor for that Units.

~~(40)~~(41) RULE 1109.1 EMISSION LIMITS mean the NOx and CO emission limits and corresponding percent O_2 correction listed in paragraphs (d)(3), (d)(4), Table 1, Table 2, Table 4, Table 5, an approved B-Plan, or an approved B-Cap.

~~(41)~~(42) STANDARD CONDITIONS for a Former RECLAIM Facility is as defined by Rule 102 – Definition of Terms .

~~(42)~~(43) STEAM METHANE REFORMER (SMR) HEATER means any Unit that is fired with gaseous fuels and transfers heat from the combusted fuel to process tubes that contain catalyst, which converts light hydrocarbons combined with steam to hydrogen.

PR 1109.1 - 6

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(43)~~(44) SULFURIC ACID FURNACE means a Unit fueled with gaseous fuels and/or hydrogen sulfide gas used to convert elemental sulfur and/or decompose spent sulfuric acid, into sulfur dioxide (SO_2) gas.

~~(44)~~(45) SULFURIC ACID PLANT means a Unit within a Petroleum Refinery, or as a separate Facility, engaged in the production of commercial grades of sulfuric acid, or regeneration of spent sulfuric acid into commercial grades of sulfuric acid.

~~(45)~~(46) SULFUR RECOVERY PLANT means a Unit within a Petroleum Refinery, or as a separate Facility, that recovers elemental sulfur or sulfur compounds from sour or acid gases and/or sour water generated by Petroleum Refineries.

~~(46)~~(47) SULFUR RECOVERY UNITS/TAIL GAS (SRU/TG) INCINERATORS means the thermal or catalytic oxidizer where the residual hydrogen sulfide in the gas exiting the sulfur recovery plant (tail gas) is oxidized to SO_2 before being emitted to the atmosphere.

~~(47)~~(48) UNIT means, for the purpose of this rule, any ~~boilers, flares, FCCUs, gas turbines, petroleum coke calciners, process heaters~~Boiler, Flare, FCCU, Gas Turbine, Petroleum Coke Calciner, Process Heater, SMR ~~heaters, sulfuric acid furnaces~~Heater, Sulfuric Acid Furnace, SRU/TG ~~incinerators~~Incinerator, or ~~vapor incinerators~~Vapor Incinerator requiring a South Coast AQMD ~~permit~~Permit and not required to comply with another NOx emission limit in a South Coast AQMD Regulation XI rule.

~~(48)~~(49) UNIT REDUCTION means the potential NOx emission reduction for a Unit if the Unit's NOx emissions were reduced from the Representative NOx Concentration to the applicable NOx concentration limit in Table 1 based on the Baseline Emissions calculated pursuant to Attachment B of this rule.

~~(49)~~(50) UNITS WITH COMBINED STACKS means two or more Units where the flue gas from these Units are combined in one or more common stack(s).

~~(50)~~(51) VAPOR INCINERATOR means a thermal oxidizer, afterburner, or other device for burning and destroying air toxics, volatile organic compounds, or other combustible vapors in gas or aerosol form in gas streams.

(d) Emission Limits

(1) An owner or operator shall not operate a ~~unit~~Unit that exceeds the applicable NOx and CO emission limits at the percent O_2 correction specified in Table 1 and the averaging time specified in Table 1 or subdivision (k), whichever is applicable pursuant to the compliance

PR 1109.1 - 7

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

schedule in
subdivision (g).

PR 1109.1 - 8

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 1: NOx AND CO EMISSION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O2 Correction (%)	Rolling Averaging Time[1]
Boilers <40 MMBtu/hour	Pursuant to paragraph (d)(3)	400	3	24-hour
Boilers ≥40 MMBtu/hour	5	400	3	24-hour
FCCU	2	500	3	365-day
	5			7-day
Flares	20	400	3	2-hour
Gas Turbines fueled with Natural Gas	2	130	15	24-hour
Gas Turbines fueled with Gaseous Fuel other than Natural Gas	3	130	15	24-hour
Petroleum Coke Calciner	5	2,000	3	365-day
	10			7-day
Process Heaters <40 MMBtu/hour	Pursuant to paragraph (d)(4)	400	3	24-hour
Process Heaters ≥40 MMBtu/hour	5	400	3	24-hour
SMR Heaters	5	400	3	24-hour
SMR Heaters with Gas Turbine	5	130	15	24-hour
SRU/TG Incinerators	30	400	3	24-hour
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	30	400	3	24-hour

1 Averaging times apply to ~~units~~Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for ~~units~~Units without CEMS are specified in subdivision (k).

PR 1109.1 - 9

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(2) Conditional NOx and CO Emission Limits

(A) An owner or operator of a ~~unit~~Unit is eligible to meet the NOx and CO emission limits in Table 2, in lieu of the NOx and CO emission limits in Table 1 provided:

(i) The Executive Officer has not issued a Permit to Construct on or after December 4, 2015 for the installation of a post combustion control device for the ~~unit~~Unit;

(ii) For a ~~process heater~~Process Heater with a ~~rated heat input capacity~~Rated Heat Input Capacity greater than or equal to 40 MMBtu/hour and less than 110 MMBtu/hour or less, the Unit Reduction calculated pursuant ~~to~~ Attachment B of this rule is less than 10 tons per year based on the applicable Table 1 NOx emission limit;

(iii) For boilers or process heaters with a Rated Heat Input Capacity greater than 110 MMBtu/hour, the Unit Reduction calculated pursuant to Attachment B of this rule is less than 20 tons per year based on the applicable Table 1 NOx emission limit;

(iv) The South Coast AQMD Permit to Construct or South Coast AQMD Permit to Operate for the ~~unit~~Unit does not have a condition that limits the NOx concentration to a level at or below the applicable Table 1 NOx emission limit;

(v) The Representative NOx Concentration of the ~~unit~~Unit is not below the applicable Table 1 NOx emission limit; and

(vi) The ~~unit~~Unit is not identified as being permanently decommissioned in an approved B-Plan for reductions in an I-Plan or approved B-—Cap pursuant to subparagraph (e)(1)(D) or (e)(2)(D).

(B) An owner or operator that meets the conditions in subparagraph (d)(2)(A) that elects to meet the NOx and CO emission limits in Table 2 in lieu of the NOx and CO emission limits in Table 1 shall:

(i) Before July 1, 2022, submit a complete South Coast AQMD permit application to apply for a permit condition that limits the NOx emissions to the applicable levels specified in Table 2; and

(ii) No later than 18 months after the South Coast AQMD Permit to Construct is issued, meet the NOx and CO emission limits

PR 1109.1 - 10

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

at the percent O_2 correction and the averaging time specified in Table 2 or subdivision (k), whichever is applicable.

PR 1109.1 - 11

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(C) Notwithstanding subparagraph (d)(2)(A) and (d)(2)(B), an owner or operator shall meet the Conditional NOx and CO Emission Limits in Table 2 in lieu of the NOx and CO Emission Limits in Table 1 if:

(i) The owner or operator is submitting a B-Plan or a B-Cap, and their ~~unit~~Unit is listed in Table D-1;

(ii) The owner or operator is submitting a B-Cap and has selected I-Plan Option 4, and their ~~unit~~Unit is listed in Table D-2.

TABLE 2: CONDITIONAL NOx AND CO EMISSION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers >110 MMBtu/hour	7.5	400	3	24-hour
FCCUs	8	500	3	365-day
	16			7-day
Gas Turbines fueled with Natural Gas	2.5	130	15	24-hour
Process Heaters 40 – ~~10~~110 MMBtu/hour	18	400	3	24-hour
Process Heaters >110 MMBtu/hour	22	400	3	24-hour
SMR Heaters	7.5	400	3	24-hour
Vapor Incinerators	40	400	3	24-hour

[1] Averaging times apply to ~~units~~Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for ~~units~~Units without CEMS are specified in subdivision (k).

(3) Boilers with Rated Heat Input Less Than 40 MMBtu/hour

An owner or operator of a boiler with a rated heat input capacity less than 40 MMBtu/hour shall:

(A) Before January 1, 2023, have a South Coast AQMD Permit that includes an enforceable emission limit that does not exceed 40 ppmv NOx and 400 ppmv CO at three percent O_2 correction and limits the

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

averaging times to Table 1 or subdivision (k), whichever is applicable.

(B) On and after January 1, 2023, not operate a boiler that exceeds 40 ppmv NOx and 400 ppmv CO at three percent O_2 correction as demonstrated pursuant to the averaging times in Table 1 or subdivision (k), whichever is applicable; and

(C) No later than six months after an owner or operator cumulatively replaces either 50 percent or more of the burners in a boiler or replaces burners that represent 50 percent or more of the heat input in a boiler, where the cumulative replacement begins from July 1, 2022, shall:

(i) Submit a complete South Coast AQMD permit application to impose a 5 ppmv NOx emission limit and a 400 ppmv CO emission limit at three percent O_2 correction that limits the averaging times to Table 1 or subdivision (k), whichever is applicable; and

(ii) Meet the emission limits pursuant to clause (d)(3)(C)(i) no later than 36 months after a South Coast AQMD Permit to Construct is issued.

(4) Process Heaters with Rated Heat Input Less Than 40 MMBtu/hour–

~~(4)~~ An owner or operator of a process heater with a rated heat input capacity less than 40 MMBtu/hour shall:

(A) Before January 1, 2023, have a South Coast AQMD Permit that includes an enforceable emission limit that does not exceed 40 ppmv NOx and 400 ppmv CO at three percent O_2 correction and limits the averaging times to Table 1 or subdivision (k), whichever is applicable;

(B) On and after January 1, 2023, not operate a process heater that exceeds 40 ppmv NOx and 400 ppmv CO at three percent O_2 correction as demonstrated pursuant to the averaging times in Table 1 or subdivision (k), whichever is applicable; and

(C) Effective [*TEN YEARS AFTER DATE OF ADOPTION*], no later than six months after an owner or operator cumulatively replaces either 50 percent or more of the burners in a process heater or replaces burners that represent 50 percent or more of the heat input

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

in a process heater, where the cumulative replacement begins from [*FIVE YEARS AFTER DATE OF ADOPTION*], shall:

~~(i)~~ Submit a complete South Coast AQMD permit application to impose a ~~9ppmv~~9 ppmv NOx emission limit and a 400 ppmv CO

(i) emission limit at three percent O_2 correction and limits the averaging times to Table 1 or subdivision (k), whichever is applicable; and

~~applicable; and~~

(ii) Meet the emission limits pursuant to clause (d)(4)(C)(i) no later than 36 months after a South Coast AQMD Permit to Construct is issued.

(5) Gas Turbines

Notwithstanding the NOx emission limits in Table 1, an owner or operator shall not operate a gas turbine that exceeds 5 ppmv NOx corrected to 15 percent O_2 ~~correction~~ based on a 24-hour rolling average during natural gas curtailment periods, where there is a shortage in the supply of pipeline natural gas due solely to supply limitations or restrictions in distribution pipelines by the utility supplying the gas, and not due to the cost of natural gas, provided:

(A) A daily gas turbine operating record is maintained that includes the actual start and stop time, total hours of operation, and type (liquid or gas) and quantity of fuel used; and

(B) This information is available to South Coast AQMD staff upon request for at least five years from the date of entry.

(6) An owner or operator of ~~units~~Units with ~~combined stacks~~Combined Stacks shall be subject to the most stringent applicable Table 1 or Table 2 NOx and CO emission limit at the percent O2 correction based on the averaging time in Table 1 or subdivision (k), whichever is applicable.

(7) An owner or operator of a ~~unit~~Unit with a CO emission limit in a South Coast AQMD Permit to Operate that was established before [DATE OF ADOPTION], shall meet the CO emission limit in the South Coast AQMD Permit to Operate in lieu of the CO emission limit specified in ~~Table 1 or Table 2.~~subdivisions (d) through (f).

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(8) An owner or operator of a ~~unit~~Unit with an averaging time less than 365-day in Table 1 or Table 2 that operates a CEMS shall be required to demonstrate compliance with the applicable NOx emission limits in Table 1, Table 2, an approved B-Plan, or an approved B-Cap six months after~~,~~ ~~either~~ the date the South Coast AQMD Permit to Operate is issued, 36 months after the Permit to Construct is issued, or completion of a compliance demonstration source test, whichever is sooner.

(9) An owner or operator of a ~~unit~~Unit subject to a 365-day rolling average in Table 1 or Table 2 shall demonstrate compliance with the Rule 1109.1 Emission Limits beginning 14 months after either the date the South Coast AQMD Permit to Operate is issued, 36 months after the Permit to Construct is issued, or completion of a compliance demonstration source test, whichever is sooner.

(e) B-Plan and B-Cap Requirements

(1) An owner or operator of a ~~facility~~Facility with six or more ~~units~~Units that elects to meet the NOx emission limits in an approved B-Plan in lieu of meeting Table 1 or Table 2 NOx emission limits shall:

(A) Before July 1, 2022, submit ~~an~~a South Coast AQMPD Permit to Construct application for a B-Plan that includes all ~~units~~Units subject to this rule, with the exception of any boiler or process heater less than 40 MMBtu/hour that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option, for review and approval pursuant to subdivision (i);

(B) Select an Alternative BARCT NOx Limit for Phase I, Phase II, and Phase III to meet the respective Phase I, Phase II, and Phase III BARCT Equivalent Mass Emissions where the Alternative BARCT NOx Limit shall not exceed:

(i) The Conditional NOx and CO limit in Table 2, for any ~~unit~~Unit that is meeting a Conditional NOx and CO Emission Limit pursuant to subparagraphs (d)(2)(A) and (d)(2)(B).

(C) Comply with a condition in the South Coast AQMD Permit to Operate that limits the NOx concentration to the Alternative BARCT NOx Limit Phase I, Phase II, and if applicable Phase III for each ~~unit~~Unit in the approved B- Plan based on the schedule

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

established in the approved I-Plan;

(D) Not include ~~emission reductions~~Emission Reductions for any ~~unit~~Unit that is permanently decommissioned; and

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(E) Not operate a ~~unit~~Unit that exceeds the Alternative BARCT NOx Limit, CO emission limit, based on the averaging time in Table 1 or ~~the~~ subdivision (k), whichever is applicable, in an approved B-Plan, based on the implementation schedule in the approved I-Plan.

(2) An owner or operator of a ~~facility~~Facility with six or more ~~units~~Units that elects to meet the NOx ~~and CO~~ emission limits in an approved B-Cap in lieu of meeting Table 1 and Table 2 NOx concentration limits shall:

(A) Before July 1, 2022, submit a B-Cap and an I-Plan to the Executive Officer that ~~includes~~include all ~~units~~Units subject to this rule, with the exception of any ~~boiler~~Boiler or ~~process heater~~Process Heater with a Rated Heat Heat Input Capacity less than 40 MMBtu/hour, that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last ~~Compliance Date~~compliance date in Table 6 for the selected I-Plan option, for review and approval pursuant to subdivision (i);

(B) Select an Alternative BARCT NOx Limit for Phase I, Phase II, and Phase III to meet the respective Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions where the Alternative BARCT NOx Limit shall not exceed;

(i) The Maximum Alternative BARCT NOx Limit for the applicable ~~unit~~Unit, specified in Table 3; and

(ii) The Conditional NOx ~~and CO~~ limit in Table 2, for any ~~unit~~Unit that is meeting a Conditional NOx ~~and CO Emission Limit~~limit pursuant to subparagraphs (d)(2)(A) or (d)(2)(B).

(C) Comply with a condition in the South Coast AQMD Permit to Operate that limits the NOx concentration to the Alternative BARCT NOx Limit for Phase I, Phase II, and if applicable Phase III for each ~~unit~~Unit in the approved B-Cap based on the schedule established in the approved I-Plan;

(D) For any ~~unit~~Unit that is permanently decommissioned, represent the permanently decommissioned ~~unit~~Unit as Table 1 NOx emissions in the Phase I, Phase II, or Phase III Facility BARCT Emission Target in an approved B-Cap, and for the ~~unit~~Unit that is permanently decommissioned the owner or operator shall:

(i) Surrender the South Coast AQMD Permit to Operate no later than the compliance date ~~for~~ in Table 6 corresponding to

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

Phase I~~ in I-Plan Option 4 and no later than ~~, Phase II, or Phase III as specified in the ~~permit submittal date for all other phases in an ~~approved I-Plan for permanently decommissioning the Unit;

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(ii) Disconnect and blind the fuel line(s) on or before the South Coast AQMD Permit to Operate is surrendered pursuant to clause (e)(2)(D)(i); and

(iii) Not sell the ~~unit for operation~~ Unit to another entity for operation within the South Coast Air Basin;

(E) Not operate any ~~unit~~Unit unless the NOx emissions for all ~~units~~Units in the approved B-Cap are in aggregate at or below the applicable Phase I, Phase II, or Phase III Facility BARCT Emission Target, based on the schedule in the approved I-Plan; and

(F) Not add a new ~~unit~~Unit that will be subject to this rule that increases the ~~facility~~Facility emissions above applicable Phase I, Phase II, or Phase III Facility BARCT Emission Target, unless:

(i) All ~~units~~Units in the approved B-Cap meet the ~~Equivalent Mass Emission~~B-Cap Annual Emissions;

(ii) The new ~~unit~~Unit is not functionally similar to any ~~unit~~Unit that was permanently decommissioned in the approved B-Cap;

(iii) The new ~~unit~~Unit will not increase overall ~~facility~~Facility throughput; and

(iv) The total amount of NOx emission reductions from ~~units~~Units that were permanently decommissioned and not replaced with functionally similar Units, represents ~~15~~40 percent or less of ~~Final Phase Facility BARCT Emission Target~~Total Facility NOx Emission Reduction in an approved B-~~-~~Cap.

TABLE 3: MAXIMUM ALTERNATIVE BARCT NOX LIMITS FOR A B-CAP

Unit	Maximum Alternative BARCT NOx Limit	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers and Process Heaters <40 MMBtu/hour	40 ppmv	3	24-~~day~~hour
Boilers and Process Heaters ≥40 MMBtu/hour	50 ppmv	3	24-~~day~~hour
FCCUs	8 ppmv	3	365-day
	16 ppm		7-day
Gas Turbines	5 ppmv	15	24-

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

			~~day~~hour
Petroleum Coke Calciners	100 tons/year	N/A	365-day
SRU/TG Incinerators	100 ppmv	3	24-~~day~~hour
Vapor Incinerators	40 ppmv	3	24-~~day~~hour

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

[1] Averaging times apply to ~~units~~Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for ~~units~~Units without CEMS are specified in subdivision (k).

(f) Interim Emission Limits

(1) An owner or operator of a ~~facility~~Facility that elects to comply with the emission limits in Table 1, Table 2, or an approved B-Plan shall not operate a ~~unit~~Unit that exceeds the applicable interim NOx and CO emission limits based on the measured O_2 correction and the averaging time in Table 4 or subdivision (k), whichever is applicable, until that ~~unit~~Unit is required to meet another Rule 1109.1 Emission Limit pursuant to the compliance schedule in paragraph (g)(1) or an approved I-Plan.

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 4: INTERIM NOx AND CO EMISSION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers and Process Heaters <40 MMBtu/hour	40	400	3	365-day
Boilers and Process Heaters ≥40 MMBtu/hour	Pursuant to paragraph (f)(2)	400	3	365-day
Flares	105	400	3	365-day
FCCUs	40	500	3	365-day
Gas Turbines fueled with Natural Gas or Other Gaseous Fuel	20	130	15	365-day
Petroleum Coke Calciners	85	2,000	3	365-day
SMR Heaters	20[2]	400	3	365-day
	60[3]			365-day
SMR Heaters with Gas Turbine	5	130	15	365-day
SRU/TG Incinerators	100	400	3	365-day
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	105	400	3	365-day

[1] Averaging times are applicable to ~~units~~Units with a CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for ~~units~~Units without CEMS are specified in subdivision (k).

[2] SMR Heaters equipped with post-combustion air pollution control equipment that was installed before [*DATE OF ADOPTION*].

[3] SMR Heaters not equipped with post-combustion air pollution control equipment as of [*DATE OF ADOPTION*].

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(2) Interim NOx emission limits for Boilers and Process Heaters
An owner or operator of a Former RECLAIM Facility shall:

(A) Not exceed the applicable interim NOx emission rate in Table 5, calculated pursuant to Attachment A Section (A-2) of this rule, for all boilers and process heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour and boilers and process heaters with a rated heat input capacity less than 40 MMBtu/hour that operate with a NOx CEMS.

TABLE 5: INTERIM NOX EMISSION RATES FOR BOILERS AND PROCESS HEATERS ≥40 MMBTU/HOUR

Units	An Owner or Operator that Elects to Comply with an Approved:	Facility NOx Emission Rate (pounds/million Btu)	Rolling Averaging Time
Boilers and Process Heaters: ≥40 MMBtu/Hour and <40 MMBtu/hour |Operating a Certified CEMS	B-Plan using I-Plan Option 3	0.02	365-day
	B-Plan	0.03	365-day

(B) Demonstrate compliance with the applicable interim NOx emission rate in Table 5 until all boilers and process heaters subject to paragraph (f)(2) meet the NOx concentration limits in Table 1, Table 2, or an approved B-Plan.

(3) An owner or operator of a Former RECLAIM Facility that elects to comply with an approved B-Cap shall not operate any ~~unit~~Unit included in the approved B-Cap unless the NOx emissions for all ~~units~~Units in the B-Cap are in aggregate at or below the Baseline Facility ~~Emission~~Emissions.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(g) Compliance Schedule

(1) An owner or operator of a ~~unit~~Unit that is required to meet the NOx and CO concentration limits specified in Table 1 shall:

(A) Before July 1, 2023, submit a complete South Coast AQMD permit application to establish a permit condition that limits the NOx concentration based on the percent O_2 correction and the averaging time in Table 1 or subdivision (k), whichever is applicable, unless the owner or operator has a South Coast AQMD Permit to Construct or a South Coast AQMD Permit to Operate with the NOx concentration limit at the percent O_2 correction, based on the averaging time specified in Table 1; and

~~(B)~~ Not operate a ~~unit~~Unit, that exceeds the NOx and CO emission limits

(B) based on the percent O_2 correction and the averaging time in Table 1 or subdivision (k), whichever is applicable:

(i) No later than 36 months after a South Coast AQMD Permit to Construct is issued; or

(ii) No later than July 1, 2023 if a permit application was not required as specified in subparagraph (g)(1)(A).

(2) I-Plan Requirements

An owner or operator with six or more ~~units~~Units that elects to meet the NOx and CO emission limits using an alternative compliance schedule to paragraph (g)(1) or that elects to comply with an approved B-Plan or B-~~-~~Cap shall:

(A) Before July 1, 2022, submit an I-Plan pursuant to paragraph (i)(1) that includes all ~~units~~Units subject to Table 1 NOx emission limits for review and approval pursuant to paragraph (i)(4), with the exception of any boiler or process heater less than 40 MMBtu/hour that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option;

~~(B) Calculate the Phase I, Phase II, or Phase III Facility BARCT Emission Targets, pursuant to Attachment B of this rule;~~

~~(C) For a B-Cap, the Phase I, Phase II, and Phase III Facility BARCT Emission Targets shall incorporate a reduction of 10 percent, pursuant to Attachment B of this rule;~~

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(D) For a B-Plan, calculate the Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions, pursuant to Attachment B of this rule;~~

~~(E) For a B-Plan, demonstrate that Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions, are equal to or less than the respective Phase I, Phase II, or Phase III Facility BARCT Emission Target;~~

~~(F) For a B-Cap, calculate the Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions, pursuant to Attachment B of this rule;~~

~~(G) For a B-Cap, demonstrate that Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions, are equal to or less than the respective Phase I, Phase II, or Phase III Facility BARCT Emission Target;~~

~~(H)~~(B) Based on the schedule in the approved I-Plan, implement emission reduction projects to comply with the emission limits in Table 1 or Table 2 or an approved B-Plan or approved B-Cap, to achieve the Phase I, Phase II, or Phase III Facility BARCT Emission Target; and

~~(I)~~(C) For an owner or operator with an approved B-Cap, demonstrate compliance with the emissions requirements and all other requirements no later than the compliance date for Phase I in I-Plan Option 4 and no later ~~54 months from South Coast AQMD Permit Application Submittal Date~~than the compliance date in Table 6 for all other phases of the selected I--Plan option in Table 6 to meet the Phase I, Phase II, or Phase III Facility BARCT Emission Targets.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 6: I-PLAN PERCENT REDUCTION TARGETS AND ~~SCHEDULE~~[1]SCHEDULE

		Phase I	Phase II	Phase III
I-Plan Option 1 for B-Plan Only	Percent Reduction Targets	70	100	N/A
	Permit Application Submittal Date	July 1, 2023	January 1, 2027	N/A
	Compliance Date	No later than 36 months after a South Coast AQMD Permit to Construct is issued		N/A
I-Plan Option 2 for B-Plan Only	Percent Reduction Targets	60	80	100
	Permit Application Submittal Date	July 1, 2023	January 1, 2025	January 1, 2028
	Compliance Date	No later than 36 months after a South Coast AQMD Permit to Construct is issued		
I-Plan Option 3 for B-Plan or B-Cap and as allowed pursuant to paragraph (g)(3)	Percent Reduction Targets	50	100	N/A
	Permit Application Submittal Date	January 1, 2025	January 1, 2029	N/A
	Compliance Date	No later than 36 months after a South Coast AQMD Permit to Construct is issued		N/A
I-Plan Option 4 for B-Cap Only	Percent Reduction Targets	50 to 60 (Still in development)	80	100
	Permit Application Submittal Date	N/A	January 1, 2025	January 1, 2028
	Compliance Date	January 1, 2024	No later than 36 months after a South Coast AQMD Permit to Construct is issued	
I-Plan Option 5 for B-Cap Only	Percent Reduction Targets	50	70	100
	Permit Application Submittal Date	July 1, 2022	July 1, 2024	January 1, 2028
	Compliance Date	No later than 36 months after a South Coast AQMD Permit to Construct is issued		

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(3) I-Plan Option 3 is only available to an owner or operator of a ~~facility~~Facility achieving a NOx emission rate of less than 0.02 pound per million BTU of heat input, based on annual emissions for the applicable ~~units~~Units as reported in the 2021 Annual Emissions Report and calculated pursuant to Attachment A, for all the boilers and process heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour based on the maximum rated capacity by [*DATE OF ADOPTION*]; for ~~units~~Units firing at less than the maximum rated capacity, mass emissions shall be less than or equal to the quantity that would occur at maximum rated capacity.

(4) An owner or operator of a ~~unit~~Unit complying with Table 2 conditional emission limits that replaces existing NOx control equipment shall:

(A) Within six months of replacing the existing NOx control equipment, be subject to the applicable Table 1 emission limit;

(B) Apply for a South Coast AQMD permit condition to limit the NOx and CO concentration to the applicable Table 1 emission limit at the corresponding percent O_2 correction and averaging times in Table 1 or subdivision (k), whichever is applicable. Replacement of existing NOx control equipment will be determined as:

(i) Existing post-combustion air pollution control equipment for an FCCU, gas turbine fueled with natural gas, process heater with a rated heat input capacity greater than or equal to 40 MMBtu/hour, or SMR Heater is replaced such that the fixed capital cost of the new components for the post-combustion air pollution control equipment exceeds 50 percent of the fixed capital cost that would be required to construct and install a comparable new ~~unit~~Unit; or

(ii) 50 percent or more of the burners in a vapor incinerator, or 50 percent or more of the rated heat input capacity of the burners in a vapor incinerator, are cumulatively replaced after [*DATE OF ADOPTION*].

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(5) An owner or operator of unit complying with clauses (d)(2)(B)(i); (d)(3)(C)(i); (d)(4)(C)(i); or subparagraphs (g)(1)(A) or (g)(5)(A) that fails to submit a complete South Coast AQMD permit application by the date specified in causes (d)(2)(B)(i); (d)(3)(C)(i); (d)(4)(C)(i); or subparagraphs (g)(1)(A) or (g)(5)(A), shall meet the applicable Rule 1109.1 Emission Limits no later than 36 months after the South Coast AQMD permit application submittal date pursuant to causes (d)(2)(B)(i), (d)(3)(C)(i), or (d)(4)(C)(i), or subparagraphs (g)(1)(A) or (g)(5)(A).~~

~~(6)~~(5) ~~An owner or operator of a unit~~a Unit exempt from the Table 1 NOx and CO emission limits pursuant to paragraphs (n)(2), (n)(3), (n)(6), (n)(7), (n)(8) or (n)(9) that exceeds the applicable exemptions limitations shall:

(A) Within six months of the exceedance, submit a complete South Coast AQMD permit application to comply with the corresponding Table 1 emission limit; and

(B) Meet the emission limits specified on Table 1 no later than 36 months after a South Coast AQMD Permit to Construct is issued.

(h) Time Extensions

(1) An owner or operator of a ~~unit~~Unit may request one 12-~~-~~month extension for each ~~unit~~Unit from the compliance date in paragraph (g)(1) or the Compliance Date in Table 6 provided:

(A) The South Coast AQMD permit application for the ~~unit~~Unit was submitted on or before the date specified in paragraph (g)(1) or the approved I-Plan; and

(B) There are specific circumstances outside of the control of the owner or operator that necessitate an extension of time.

(2) An owner or operator of a ~~unit~~Unit with an approved I-Plan may request a time extension from the Compliance Date in Table 6 for a ~~unit~~Unit provided:

(A) The South Coast AQMD permit application for the ~~unit~~Unit was submitted on or before the date specified in the approved I-Plan;

(B) The month and year for the ~~unit's~~Unit's scheduled turnaround and the month and year for the ~~unit's~~Unit's subsequent turnaround is submitted in writing at the time of South Coast AQMD permit application submittal; and

(C) One or more of the following occurred:

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(i) The South Coast AQMD Permit to Construct for the ~~unit~~Unit was issued after the scheduled turnaround date or the South Coast AQMD Permit to Construct for the ~~unit~~Unit was issued more than ~~24~~18 months after the South Coast AQMD permit application was submitted, and either:

(ii) The subsequent scheduled turnaround for the ~~unit~~Unit will not occur until 12 months after the Compliance Date in the approved I-Plan; or

(iii) The subsequent scheduled turnaround for the ~~unit~~Unit will occur more than 48 months after the South Coast AQMD Permit to Construct was issued.

(3) An owner or operator that requests a time extension pursuant to paragraphs (h)(1) or (h)(2) shall submit the request in writing to the Executive Officer no later than 90 days prior to the Compliance Date in paragraph (g)(1) or the approved I-Plan for the ~~unit~~Unit. The time extension request shall include:

(A) The phase and ~~unit~~Unit needing a time extension;

(B) The date the South Coast AQMD permit application was submitted;

(C) The additional time needed to complete the emission reduction project;

(D) Specify if the time extension request is for paragraph (h)(1) or (h)(2);

(E) For time extension requests for paragraph (h)(2), provide the month and year of the scheduled turnaround, and the subsequent turnaround, if applicable, for the ~~unit~~Unit; and

(F) The reason(s) a time extension is requested.

(4) The Executive Officer will review the request for the time extension and act on the request within ~~60~~30 days of receipt provided an owner or operator:

(A) Meets the requirements of paragraph (h)(1) or (h)(2), as applicable;

(B) Submitted the written request within the timeframe and includes the applicable information specified in paragraphs (h)(1) and (h)(2); and

(C) For a time extension request pursuant to paragraphs (h)(1) and (h)(2), the owner or operator shall at a minimum:

(i) For delays due to missed milestones, provide information on schedules and/or construction plans documenting the key milestones and which key milestone(s) were delayed with an

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explanation actions the operator took to ensure milestones were met and why the delay necessitates additional time;

(ii) For delays related to other agency approvals, provide information to substantiate that the submittal of information to the agency was timely, the date when application was the approval was requested, and documentation from the agency of reason for the delay;

(iii) For delays related to the delivery of parts or equipment, provide purchase orders, invoices, and communications from vendors that demonstrate that equipment was ordered in a timely fashion and delays are outside of the control of the operator; and

(iv) For delays related to contract workers, source testers, installers, or other services, provide an explanation of the service, when the service was requested, the response time, and information to substantiate why the delay necessitates additional time.

(D) For a time extension request allowed under paragraphs (h)(2), the owner or operator shall provide documentation to substantiate that one of the provisions under subparagraph (h)(2)(C) have been met.

(5) If the Executive Officer requests additional information to substantiate the time extension request, the owner or operator shall provide that information within the timeframe specified by the Executive Officer.

(6) If the Executive Officer notifies the owner or operator of approval of a time extension request, the owner or operator shall meet the emission limits in Table 1, an approved B-Plan, or an approved B-Cap within timeframe in the approval, and the approval represents an amendment to the I-Plan.

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(7) If the Executive Officer notifies the owner or operator of a disapproval of a time extension request, the owner or operator shall meet the emission limits in Table 1, an approved B-Plan, or an approved B-Cap within 60 calendar days after receiving notification of disapproval of the time extension request or pursuant to the compliance schedule in paragraph (g)(1) or the schedule in an approved I-Plan, whichever is later.

(i) I-Plan, B-Plan, and B-Cap Submittal and Approval Requirements

(1) I-Plan Submittal Requirements

An owner or operator that elects to implement an I-Plan pursuant to paragraph (g)(2) to meet the Alternative BARCT NOx Limits in an approved B-Plan ~~or~~, or the BARCT Equivalent Mass Emission Cap in an approved B-Cap shall submit an I-Plan to the Executive Officer for review and approval that:

(A) Identifies all Facilities by Facility identification number under same ownership subject to the rule that are included in the I-Plan;

~~(A)~~(B) Identifies each ~~unit~~Unit subject to the rule by device identification number with a description of each ~~unit~~Unit, with the exception of any boiler or process heater less than 40 MMBtu/hour that will meetthe NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option;

~~(B)~~(C) For ~~facilities~~Facilities to use the time extension pursuant to paragraph (h)(2), identifies the anticipated start and end date (month and year) of the turnaround schedule for each ~~unit~~Unit;

~~(C)~~(D) Specifies either I-Plan Option 1 (for a B-Plan only), I-Plan Option (for a B-Plan only) 2, I-Plan Option 3 (for a B-Plan or B-Cap), I--Plan Option 4 (for a B-Cap only), or I-Plan Option 5 (for a B-Cap only) in Table 6;

~~(D) Calculates the Phase I, Phase II, or Phase III Facility BARCT Emission Target, pursuant to Attachment B of this rule;~~

(E) For a B-Plan, identifies each ~~unit~~Unit that meets the requirements under subparagraph (d)(2)(A) for use of a conditional NOx emission limit in Table 2 and the owner or operator submitted a complete South Coast AQMD permit application pursuant to clause (d)(2)(B)(i);

(F) For the selected I-Plan option specified pursuant to subparagraph

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(i)(1)(~~B~~D), calculates the Phase I, Phase II, or Phase III Facility BARCT Emission Target, pursuant to Attachment B of this rule; and

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(G) Identifies each ~~unit~~Unit by device identification number with a description of each ~~unit~~Unit, that cumulatively meets Phase I, Phase II, or Phase III Facility BARCT Emission Target.

(2) B-Plan Submittal Requirements

An owner or operator that elects to meet Alternative BARCT NOx Limits in an approved B-Plan pursuant to paragraph (e)(1), shall submit a B-Plan to the Executive Officer for review that:

(A) Identifies all Facilities by Facility identification number under same ownership subject to the rule that are included in the B-Plan;

~~(A)~~(B) Identifies for each ~~unit~~Unit subject to the rule by device identification number with a description of each ~~unit~~Unit, with the exception of any boiler or process heater less than 40 MMBtu/hour that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option;

~~(B)~~(C) Specifies the Alternative BARCT NOx Limit for Phase I, Phase II, and if applicable Phase III of the approved I-Plan;

~~(C)~~(D) Calculates the Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions using the Alternative BARCT NOx Limits ~~identified in subparagraph (g)(2)(B)~~, as calculated pursuant to Attachment B of this rule; and

~~(D)~~(E) Demonstrates that Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions are less than the respective Phase I, Phase II, or Phase III Facility BARCT Emission Target.

(3) B-Cap Submittal Requirements

An owner or operator that elects to meet the ~~Alternative~~ BARCT ~~NOx Limits~~Equivalent Mass Emission Cap in an approved B-Cap pursuant to paragraph (e)(2), shall submit a B-Cap to the Executive Officer for review that:

(A) Identifies all Facilities by Facility identification number under same ownership subject to the rule that are included in the B-Cap;

~~(A)~~(B) Identifies each ~~unit~~Unit subject to the rule by the device identification number with a description of the ~~unit~~Unit, with the exception of any boiler or process heater less than 40 MMBtu/hour that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in Table 6 for the selected I-Plan option, and:

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(B)~~(C) Specifies the Alternative BARCT NOx Limit that is at or below Maximum Alternative BARCT NOx Limit in Table 3;

~~(C)~~(D) Identifies any ~~unit~~Unit that will be permanently decommissioned for each phase of the approved I-Plan;

~~(D)~~(E) Identifies any ~~unit~~Unit that will have ~~a reduction~~other reductions in ~~throughput~~mass emissions for each phase of the approved I-Plan;

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(E)~~(F) Calculates the Phase I, Phase II, or Phase III BARCT ~~Equivalent Mass~~B-Cap Annual Emissions using ~~the~~ emission reduction strategies ~~identified in subparagraph (g)(3)(B)~~; as calculated pursuant to Attachment B of this rule; and

(G) Demonstrates that Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions, are less than the respective Phase I, Phase II, or Phase III Facility BARCT Emission Target ~~that incorporates a 10 percent reduction pursuant to subparagraph (g)(2)(C);~~.

~~(F)~~(H) Demonstrates that the B-Cap and I-Plan submittal satisfies the environmental benefit definition in U.S. EPA's January 2001 guidance document entitled "Improving Air Quality With Economic Incentive Programs."

(4) I-Plan, B-Plan, and B-Cap Review and Approval Process

(A) Within 30 days of receipt, the Executive Officer will conduct an initial review of the applicable plan(s) and request any additional information that was not provided in subparagraph (i)(4)(B).

~~(A)~~(B) The Executive Officer will notify the owner or operator in writing whether the I-Plan, B-Plan, or B-Cap is approved or disapproved based on the following criteria:

(i) The I-Plan contains information required in paragraph (i)(1), the B-Plan contains information required in paragraph (i)(2), and the B-Cap contains information required in paragraph (i)(3);

(ii) The owner or operator demonstrates that the requirements of subparagraphs (d)(2)(A) and (d)(2)(B) have been met for any ~~unit~~Unit not listed in Attachment D-2 that is meeting a Table 2 conditional NOx emission limit, in lieu of a Table 1 NOx emission limit;

(iii) For a B-Plan, the Phase I, Phase II, or Phase III Equivalent BARCT Emissions are less than or equal to the respective Phase I, Phase II, or Phase III Facility BARCT Emission Target ~~as required in subparagraph (g)(2)(B)~~;

(iv) For a B-Cap, the Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions are less than or equal to the respective Phase I, Phase II, or Phase III Facility BARCT Emission Target ~~that incorporates a 10 percent reductions pursuant to subparagraph (g)(2)(C)~~;

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(v) For a B-Cap, the NOx concentration limit for any ~~unit~~Unit does not exceed the Maximum Alternative BARCT NOx Limits in Table 3.

(C) The Executive Officer shall not disapprove the I-Plan, B-Plan, or B-Cap or a modification to these Plan(s) if the Facility provides the information required in (i)(4)(B).

~~(B)~~(D) Within ~~30~~60 days of receiving written notification from Executive Officer that the I-Plan, B-Plan, or B-Cap is ~~disapproved~~deficient, the owner or operator shall correct any deficiencies and re-submit the I-Plan, B-Plan, or B-Cap.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(C) Upon receiving written notification from the Executive Officer that the I-Plan, B-Plan, or B-Cap re-submitted pursuant to subparagraph (i)(4)(B) is disapproved, the owner or operator shall comply with the compliance schedule pursuant to paragraph (g)(1).~~

(E) An I-Plan, B-Plan or B-Cap shall be subject to Rule 221 – Plans.

(5) Modifications to an Approved I-Plan, an Approved B-Plan, and an Approved B-Cap

(A) An owner or operator that seeks approval to modify an approved I-Plan, an approved B-Plan, or an approved B-Cap shall submit a request in writing to the Executive Officer to modify an Approved I-Plan, an Approved B-Plan, and an Approved B-Cap.

(B) The modification request submitted pursuant to subparagraph (i)(5)(A) shall include all the plan submittal requirements pursuant to paragraph (i)(1) for an approved I-Plan, paragraph (i)(2) for a modification of an approved B-Plan, or paragraph (i)(3) for a modification of an approved B-Plan;

(C) An owner or operator shall modify an approved I-Plan, B-Plan, or B-Cap if:

(i) A ~~unit~~Unit identified as meeting Table 2 no longer meets the requirements of subparagraph (d)(2)(A) or (d)(2)(B);

(ii) A ~~unit~~Unit in an approved B-Cap or B-Plan, identified as meeting Table 2 for establishing the Phase I, Phase II, or Phase III BARCT Facility Emission Target, is permanently decommissioned;

(iii) A higher Alternative BARCT NOx Limit will be proposed in the South Coast AQMD permit application than the Alternative BARCT NOx Limit for that ~~unit~~Unit in the currently approved I-Plan, B-Plan, or B-Cap; or

~~(iv) Any emission reduction project is moved to a later implementation phase, any emission reduction project is moved between phases, or any emission reduction project is removed from a phase; or~~

~~(v)~~(iv) The owner or operator receives written notification from the Executive Officer that modifications to the I-Plan, B-Plan, or B-Cap are needed.

(D) Review and approval of any modifications to an I-Plan, B-Plan, or

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

B-Cap shall conducted in accordance with the review and approval process pursuant to paragraph (i)(4).

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(6) Notification of Pending Approval of an I-Plan, B-Plan, or B-Cap
The Executive Officer will make the I-Plan, B-Plan, or B-Cap or modifications to an approved I-Plan, B-Plan, or B-Cap available to the public on the South Coast AQMD website 30 days prior to approval.

(7) Plan Fees
The review and approval of an I-Plan, B-Plan, and B-Cap, or review and approval of a modification of an approved I-Plan, B-Plan, and B-Cap shall be subject to applicable plan fees as specified in Rule 306 – Plan Fees.

(j) CEMS Requirements

(1) An owner or operator of a Former RECLAIM Facility with a ~~unit~~Unit with a rated heat input capacity of greater than or equal to 40 MMBtu/hour shall install, certify, operate, and maintain a CEMS to measure NOx and O_2 pursuant to the applicable Rule 218.2 and Rule 218.3 requirements to demonstrate compliance with NOx emission limits at the corresponding percent O_2 correction and averaging times.

(2) An owner or operator of a Former RECLAIM Facility with a sulfuric acid furnace subject to the emission limits in Table 1, Table 4, an approved B-Plan or an approved B-Cap shall:

(i) Install, certify, operate, and maintain a CEMS to measure NOx pursuant to the applicable Rules 218.2 and 218.3 requirements to demonstrate compliance with the Rule 1109.1 Emissions Limits; and

(ii) Within 12 months from [*DATE OF ADOPTION*] shall install, certify, operate, and maintain a CEMS that complies with the Rules 218.2 and 218.3 requirements to measure O_2 and demonstrate compliance with the Rule 1109.1 Emission Limits at the corresponding percent O_2 correction.

(3) An owner or operator of a ~~unit~~Unit with a CEMS that measures CO at [*DATE*
OF ADOPTION] must operate and maintain the CO CEMS pursuant to the applicable Rules 218.2 and 218.3 requirements to demonstrate compliance with the Table 1, Table 2, or Table ~~3~~4 CO emissions limits and certify the CEMS within 12 months of [*DATE OF ADOPTION*] pursuant to the applicable Rules 218.2 and 218.3 requirements.

(4) An owner or operator of a Former RECLAIM Facility for a ~~unit~~Unit with a CEMS shall exclude invalid CEMS data pursuant to Rule 218.2 –

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

Continuous Emission Monitoring System: General Provisions and Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications.

(5) Missing Data Procedures for a Facility Complying with a B-Cap

An owner or operator of a ~~unit~~Unit with an approved B-Cap with a non-operational CEMS that is not collecting data, shall:

(A) Calculate missing data using the average of the recorded emissions for the hour immediately before the missing data period and the hour immediately after the missing data period, if the missing data period is less than or equal to 8 continuous hours; or

(B) Calculate missing data using the maximum hourly emissions recorded for the previous 30 days, commencing on the day immediately prior to the day the missing data occurred, if the missing data period is more than 8 continuous hours.

(k) Source Test Requirements

(1) An owner or operator of a ~~unit~~Unit that is not required to install and operate a CEMS pursuant to subdivision (i) shall be required to conduct a source test, with a duration of at least 15 minutes but no longer than two hours, to demonstrate compliance with Rule 1109.1 Emission Limits pursuant to the source test schedule in either Table 7 or Table 8.

(2) Source Test Schedule for Units without Ammonia Emissions in the Exhaust

An owner or operator of a ~~unit~~Unit that is not required to install and operate a CEMS pursuant to subdivision (i) and does not vent to post-combustion air pollution control equipment with ammonia injection, shall demonstrate compliance with the applicable Rule 1109.1 Emission Limits by conducting source tests according to the schedule in Table 7.

(3) An owner or operator of a Unit with source testing requirements in a South Coast AQMD Permit to Operate for NOx or CO shall follow the applicable source test requirements in the South Coast AQMD Permit to Operate in lieu of the source test requirements in Table 7 and Table 8.

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

TABLE 7: SOURCE TESTING SCHEDULE
FOR UNITS WITHOUT AMMONIA EMISSIONS IN THE EXHAUST

Combustion Equipment	Source Test Schedule
Vapor Incinerators less than 40MMBtu/hr, Flares	• Conduct source test simultaneously for NOx and CO within 36 months from previous source test and every 36 months thereafter
All Other Units	
Units Operating without NOx or CO CEMS	• Conduct source test simultaneously for NOx and CO within 12 months of being subject to Rule 1109.1 Emission Limit and quarterly thereafter • Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit if four consecutive quarterly source tests demonstrate compliance with the NOx and CO emission limits • If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the NOx and CO emission limits prior to resuming annual source tests
Units operating with NOx CEMS and without CO CEMS	• Conduct source test for CO within 12 months from previous source test and every 12 months thereafter
Units operating without NOx CEMS and with CO CEMS	• Conduct source test for NOx during the first 12 months of being subject to Rule 1109.1 Emission Limit and quarterly thereafter • Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit if four consecutive quarterly source tests demonstrate compliance with the NOx and CO emission limits • If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the NOx emissions limits prior to resuming annual source tests

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(3)~~(4) Source Test Schedule for Units with Ammonia Emissions in the Exhaust

An owner or operator of a ~~unit~~Unit with post-combustion air pollution control equipment that requires ammonia injection shall demonstrate compliance with the applicable Rule 1109.1 Emission Limit and ammonia South Coast AQMD permit limit by conducting a source test according to the schedule in Table 8.

TABLE 8: SOURCE TESTING SCHEDULE FOR UNITS WITH AMMONIA EMISSIONS IN THE EXHAUST

Combustion Equipment	Source Test Schedule
Units operating without NOx, CO, or ammonia CEMS	• Conduct source test simultaneously for NOx, CO, and ammonia quarterly during the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit and quarterly thereafter • Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit if four consecutive quarterly source tests demonstrate compliance with the CO, NOx, and ammonia emission limit • If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the NOx, CO, and ammonia emissions limits prior to resuming annual source tests

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

Combustion Equipment	Source Test Schedule
Units operating with NOx CEMS and without CO and ammonia CEMS	• Conduct source test for CO and ammonia quarterly during the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit and quarterly thereafter • Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit if four consecutive quarterly source tests demonstrate compliance with the CO and ammonia emission limit • If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the CO and ammonia emissions limits prior to resuming annual source tests
Units operating with NOx and CO CEMS and without ammonia CEMS	• Conduct source test for ammonia quarterly during the first 12 months of being subject to an ammonia South Coast AQMD permit limit and quarterly thereafter • Source tests may be conducted annually after the first 12 months of being subject to an ammonia South Coast AQMD permit limit if four consecutive quarterly source tests demonstrate compliance with the ammonia emission limit • If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the ammonia emissions limits prior to resuming annual source tests
Units operating with NOx and ammonia CEMS and without CO CEMS	• Conduct source test for CO within 12 months from previous source test and every 12 months thereafter
Units operating with ammonia CEMS and without NOx or CO CEMS	• Conduct source tests to determine compliance with NOx and CO emission limits pursuant to Table 7

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(4)~~(5) An owner or operator that elects to install and operate a CEMS to demonstrate compliance with the applicable Rule 1109.1 Emission Limits or ammonia South Coast AQMD permit limit at the corresponding percent O_2 correction shall meet the CEMS requirements under subdivision (j).

~~(5)~~(6) An owner or operator of with a ~~unit~~Unit subject to a Rule 1109.1 Emission Limit or ammonia South Coast AQMD permit limit, that is not required to install and operate a CEMS pursuant to subdivision (i) and has not conducted a source test within the schedule in Table 7 or Table 8, shall conduct a source test within:

(A) Six months from being subject to the Rule 1109.1 Emission Limit for ~~units~~Units with a rated heat input capacity greater than or equal to 20 MMBtu/hour.

(B) 12 months from being subject to the Rule 1109.1 Emission Limit for ~~units~~Units with a rated heat input capacity less than 20 MMBtu/hour.

~~(6)~~(7) An owner or operator of a new or modified ~~unit~~Unit shall conduct the initial source tests within six months from commencing operation.

~~(7)~~(8) An owner or operator of a ~~unit~~Unit required to conduct a source test pursuant to subdivision (k) shall:

(A) For ~~units~~Units that receive a South Coast AQMD Permit to Construct to comply with Rule 1109.1 Emission Limit, submit a source test protocol, that includes an averaging time of ~~at least~~no less than 15 minutes but no longer than 2 hours, for approval ~~within 60 days after the Permit to Construct was issued~~ at least 90 days prior to conducting the source test unless otherwise approved by the Executive Officer;

(B) For ~~units~~Units that receive a South Coast AQMD permit condition that limits NOx or CO to a Rule 1109.1 Emission Limit, submit a source test protocol, that includes an averaging time of ~~at least~~no less than 15 minutes but no longer than 2 hours, for approval within 60 days after being subject to a Rule 1109.1 Emission limit, unless otherwise approved by the Executive Officer, and

(C) Conduct the source test within 90 days after a written approval of the source test protocol by the Executive Officer is distributed unless otherwise approved by the Executive Officer.

~~(8)~~(9) At least one week prior to conducting a source test, an owner or operator of

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

a ~~unit~~Unit shall notify the Executive Officer by calling 1-800-CUT-SMOG of the intent to conduct source testing and shall provide:

(A) Facility name and identification number;

(B) Device identification number; and

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(C) Date when source test will be conducted.

~~(9)~~(10) Unless requested by the Executive Officer, after the approval of the initial source test protocol pursuant to paragraph (k)(7), an owner or operator is not required to resubmit a source test protocol for approval pursuant to paragraph (k)(7) if:

(A) The method of operation of the ~~unit~~Unit has not been altered in a manner that requires a South Coast AQMD permit application submittal;

(B) Rule or South Coast AQMD permit emission limits have not become more stringent since the previous source test;

(C) There have been no changes in the source test method that is referenced in the approved source test protocol; and

(D) The approved source test protocol is representative of the operation and configuration of the ~~unit~~Unit.

~~(10)~~(11) An owner or operator of a ~~unit~~Unit shall conduct the source test using a South Coast AQMD approved contractor under the Laboratory Approval Program:

(A) Using a South Coast AQMD approved source test protocol;

(B) Using at least one of the following test methods:

(i) South Coast AQMD Source Test Method 100.1 – Instrumental Analyzer Procedures for Continuous Gaseous Emission Sampling; or

(ii) South Coast AQMD Source Test Method 7.1 – Determination of Nitrogen Oxide Emissions from Stationary Sources and South Coast AQMD Source Test Method 10.1 – Carbon Monoxide and Carbon Dioxide by Gas Chromatograph/Non-Dispersive Infrared Detector – Oxygen by Gas Chromatograph-Thermal Conductivity (GC/TCD);

(iii) South Coast AQMD Source Test Method 207.1 for Determination of Ammonia Emissions from Stationary Sources; or

(iv) Any other test method determined to be equivalent and approved by the Executive Officer, and either the California Air Resources Board or the U. S. Environmental Protection Agency, as applicable.

(C) During operation other than startup and shutdown; and

(D) In as-found operating condition.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

~~(11)~~(12) An owner or operator of a ~~unit~~Unit shall submit all source test reports, including the source test results and a description of the ~~unit~~Unit tested, to the Executive Officer within 60 days of completion of the source test.

~~(12)~~(13) Emissions determined to exceed any limits established by this rule by any of the reference test methods in subparagraph (k)(9)(B) shall constitute a violation of the rule.

~~(13)~~(14) An owner or operator of a ~~unit~~Unit that exceeds any limits established by this rule by any of the reference test methods in subparagraph (k)(9)(B) shall inform the Executive Officer within 72 hours from the time an owner or operator knew of excess emissions, or reasonably should have known.

(l) Diagnostic Emission Checks

(1) An owner or operator of a ~~unit~~Unit required to perform a source test every 36 months pursuant to subdivision (k) shall:

(A) Perform diagnostic emissions checks of NOx, CO, and O_2 emissions, with a portable NOx, CO, and O_2 analyzer that is calibrated, maintained and operated in accordance with manufacturers specifications and recommendations of the South Coast AQMD Combustion Gas Periodic Monitoring Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Combustion Sources Subject to Rules 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, 1146 – Emissions of Oxides of Nitrogen From Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, and 1146.1 – Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters.

(B) Conduct the diagnostic emission checks by a person who has completed an appropriate training program approved by South Coast AQMD in the operation of portable analyzers and has received a certification issued by the South Coast AQMD.

(C) Conduct the diagnostic test every 365 days or every 8760 operating hours, whichever occurs earlier.

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(2) A diagnostic emissions check that finds the emissions in excess of those allowed by this rule or a South Coast AQMD permit condition shall not constitute a violation of this rule if an owner or operator corrects the problem and demonstrates compliance with another diagnostic emissions check within 72 hours from the time an owner or operator knew of excess emissions, or reasonably should have known, or shut down the ~~unit~~Unit by the end of an operating cycle, whichever is sooner. Any diagnostic emission check conducted by South Coast AQMD staff that finds emissions in excess of those allowed by this rule or a South Coast AQMD permit condition shall be a violation.

(m) Monitoring, Recordkeeping, and Reporting Requirements

(1) Operating Log

An owner or operator of a ~~unit~~Unit shall maintain the following daily records for each ~~unit~~Unit, in a manner approved by the Executive Officer:

(A) Time and duration of startup and shutdown events;

(B) Total hours of operation;

(C) Quantity of fuel; and

(D) Cumulative hours of operation to date for the calendar year.

(2) An owner or operator of a ~~facility~~Facility that elects to meet the NOx emission limits in an approved B-Cap pursuant to paragraph (e)(2) shall:

(A) Maintain CEMS for all applicable equipment or an enforceable method approved by the Executive Officer to determine daily mass emissions for those ~~units~~Units without CEMS;

(B) Maintain daily records of mass emissions, in pounds (lbs) per day, from all ~~units~~Units included in an approved B-Cap including:

(i) Emissions during start-ups, shutdowns, and maintenance;

(ii) CEMS data identified as invalid and justification;

(iii) Data substituted for missing data pursuant to paragraph (j)(5);

(C) Demonstrate compliance with the Facility BARCT Emission Target in the B-Cap on a daily basis from 365-day rolling average;

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(3) An owner or operator subject to the interim emission rate pursuant to paragraph (f)(2) shall maintain the following daily records for each ~~unit~~Unit, in a manner approved by the Executive Officer:

(A) Actual daily mass emissions, in lbs., for all boilers and process heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour;

(B) Combined maximum rated heat input for all boilers and process heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour; and

(C) Calculated interim NOx emission rate pursuant to Attachment A Section (A-2) of this rule.

(4) An owner or operator of a ~~unit~~Unit shall keep and maintain the following records on-site for five years, except that all data gathered or computed for intervals of less than 15 minutes shall be maintained for a minimum of 48 hours, and shall make them available to the Executive Officer upon request:

(A) CEMS data;

(B) Source tests reports;

(C) Diagnostic emission checks; and

(D) Written logs of startups, shutdowns, and breakdowns, all maintenance, service and tuning records, and any other information required by this rule.

(5) An owner or operator of a boiler or process heater that is exempt from the applicable Table 1 emission limits pursuant to paragraphs (n)(5) and (n)(6), or an owner or operator of a flare that is exempt from the applicable Table 1 emission limits pursuant to subparagraph (n)(8)(A) shall:

(A) Within 90 days of [*DATE OF ADOPTION*], install and operate a non-resettable totalizing time meter or a fuel meter unless a metering system is currently installed and the fuel meter is approved in writing by the Executive Officer.

(B) Within 90 days of [*DATE OF ADOPTION*], each non-resettable totalizing time meter or a fuel meter required under subparagraph (m)(4)(A) that requires dependable electric power to operate shall be equipped with a permanent supply of electric power that cannot be unplugged, switched off, or reset except by the main power supply circuit for the building and associated equipment or the safety shut-off switch.

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(C) Ensure that the continuous electric power to the non-resettable totalizing time meter or fuel meter required under subparagraph (m)(4)(A) may only be shut off for maintenance or safety.

(D) Within 90 days of [*DATE OF ADOPTION*], ensure that each non-resettable totalizing time meter or fuel meter is calibrated and recalibrate the meter annually, thereafter, based on the manufacturer's recommended procedures. If the non-resettable totalizing time or fuel meter was calibrated within one year prior to [*DATE OF ADOPTION*], the next calibration shall be conducted within one year of anniversary date of the prior calibration.

(E) Monitor and maintain hours of operation records as follows:

(i) For the hours per year validation, using a calibrated non-resettable totalizing time meter or equivalent method approved in writing by the Executive Officer; or

(ii) For the annual throughput limit equivalent to hours per year validation, using a calibrated fuel meter or equivalent method approved in writing by the Executive Officer.

(6) An owner or operator of a vapor incinerator that is exempt from the applicable Table 1 NOx emission limits pursuant to paragraph (n)(9) shall record:

(A) The annual throughput using a calibrated fuel meter or equivalent method approved in writing by the Executive Officer; and

(B) Emissions using a source test pursuant to subdivision (k) or by using a default emission factor approved in writing by the Executive Officer.

(7) An owner or operator of a ~~unit~~Unit subject to the compliance schedule in subparagraphs (d)(3)(B), (d)(4)(B), and (g)(3)(B) shall maintain records of burner replacement, including number of burners and date of installation.

(8) An owner or operator of a ~~unit~~Unit subject to the compliance schedule in subparagraph (g)(3)(A) shall maintain records of the date the existing post-combustion control equipment was installed or replaced.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(n) Exemptions

(1) Boilers or Process Heater with a Rated Heat Input Capacity 2 MMBtu/hour or less

The provisions of this rule shall not apply to an owner or operator of a boiler or process heater with a rated heat input capacity 2 MMBtu/hour or less that are fired with liquid and/or gaseous fuel and used exclusively for space or water heating and are subject to Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters.

(2) Low-Use Boilers with a Rated Heat Capacity of less than 40 MMBtu/hour

An owner or operator of a boiler with a rated heat capacity of less than 40 MMBtu/hour that operates 200 hours or less per calendar year, or with an annual throughput limit equivalent to 200 hours per calendar year, shall be exempt from the requirements in:

(A) Subdivisions (d) provided:

(i) The boiler has an enforceable South Coast AQMD permit conditions that limits the operating hours to 200 hours or the annual throughput equivalent to 200 hours; and

(ii) The boiler operates in compliance with the permit conditions pursuant to clause (n)(2)(A)(ii).

(B) Subdivisions (k) and (l) provided the ~~unit~~Unit is not included in an approved B-Cap.

(3) Low-Use Process Heater with a rated heat input capacity greater than or equal to 40 MMBtu/hour

An owner or operator of a process heater with a rated heat input capacity greater than or equal to 40 MMBtu/hour that is fired at less than 15 percent of the rated heat input capacity on an annual basis, shall be exempt from the applicable emission limits in Table 1, Table 2, and an approved B-Plan.

(4) An owner or operator of a FCCU that must bypass the post-combustion air pollution control equipment to conduct boiler inspections required under California Code of Regulations, Title 8, Section 770(b) shall be exempt from the applicable Rule 1109.1 Emission Limits during the required boiler inspections.

(5) FCCU Startup Heater

An owner or operator of a process heater which is used only for startup of a FCCU and that process heater is operated for 200 hours or less per calendar year shall be exempt from the requirements in:

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(A) Subdivisions (d) provided:

(i) The process heater or boiler has a South Coast AQMD permit that specifies conditions that limits the operating hours to 200 hours or less; and

(ii) The process heater or boiler operates in compliance with the permit condition pursuant to clause (n)(5)(A)(i).

(B) Subdivisions (k) and (l) provided the ~~unit~~Unit is not included in an approved B-Cap.

(6) Startup or Shutdown Boilers at Sulfuric Acid Plants

An owner or operator of a process heater used for startup or a boiler used during startup or shutdown at a sulfuric acid plant that does not exceed 90,000 MMBtu of annual heat input per calendar year shall be exempt from the requirements in subdivisions (d), (i), (j), and (k) provided:

(A) The process heater or boiler has a South Coast AQMD permit that specifies conditions that limits the heat input to 90,000 MMBtu or lower per calendar year; and

(B) The process heater or boiler operates in compliance with the South Coast AQMD permit condition specified in subparagraph (n)(6)(A).

(7) Boiler or Process Heater Operating Only the Pilot

An owner or operator of a boiler or process heater operating only the pilot prior to startup or after shutdown shall be exempt from the emission limits in paragraphs (d)(3), (d)(4), Table 1, Table 2, Table 3, an approved B-Plan, or an approved B-Cap and may exclude those emission from the rolling average calculation pursuant to Attachment A of this rule.

(8) Flares

(A) An owner or operator of a flare that emits less than or equal to 550 pounds of NOx or less per year shall be exempt from the requirements in subdivisions (d), (g) and (k), provided:

(i) The flare has enforceable South Coast AQMD permit conditions that limits the emissions to not exceed 550 pounds of NOx per year; and

(ii) The flare is in compliance with the permit condition pursuant to clause (n)(8)(A)(i).

(B) An owner or operator of an open flare, which is an unshrouded flare, shall not be required to conduct source testing pursuant to subdivision (k).

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(9) Vapor Incinerators

An owner or operator of a vapor incinerator that emits less than 100 pounds of NOx per year shall be exempt from the requirements in subdivision (d) provided the vapor incinerator:

(A) Has enforceable South Coast AQMD permit conditions that limit NOx emissions to less than 100 pounds of NOx per year through operating hours or annual throughput; and

(B) Operates in compliance with the permit condition pursuant to subparagraph (n)(9)(A).

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

ATTACHMENT A

SUPPLEMENTAL CALCULATIONS

(A-1) Rolling Average Calculation for Emission Data Averaging

$$C_{Avg} = \sum_{i=t}^{t+N-1} C_i/N$$

Where:

C_{Avg} = The average emission concentration at time t

t = Time of average concentration (hours)

C_i = The measured or calculated concentration for a ~~unit~~Unit with a CEMS at the i[th] subset of data; one-hour for a ~~unit~~Unit with an averaging time of 24 hours or less and 24-hour for a ~~unit~~Unit with an averaging time of greater than 24 hours

N = Averaging time (hours).

(A-2) Interim NOx Emission Rate Calculation

An owner of operator shall calculate interim NOx emission rates as follows:

(A-2.1) Hourly Mass Emissions (lbs/hour)

Sum the actual annual mass emissions of all boilers and process heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour and any boilers and process heaters with a rated heat input capacity less than 40 MMBtu/hour that operate a certified CEMS, and divide by 8760 hours for lbs per hour.

(A-2.2) Combined Maximum Heat Input (MMBtu/hour)

Sum the combined maximum rated heat input for all boilers and process heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour and any boilers and process heaters with a rated heat input capacity less than 40 MMBtu/hour that operate a certified CEMS.

(A-2.3) Interim Facility Wide NOx Emission Rate (lbs/MMBtu)

Divide the Hourly Mass Emissions in Section (A-2.1) by the combined Maximum Heat Input in Section (A-2.2) to determine the interim NOx emission rate.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

ATTACHMENT B

CALCULATION METHODOLOGY FOR THE I-PLAN, B-PLAN, AND B-CAP

The purpose of this attachment is to provide details regarding how key elements of the I-Plan, B-Plan, and B-Cap are calculated. Key calculations provided in this attachment include: Baseline Unit Emissions and Baseline Facility Emissions; Final Phase Facility BARCT Emission Target; Total Facility NOx Emission Reductions; Phase I, Phase II, or Phase III Facility BARCT Emission Target; Phase I, Phase II or Phase III BARCT Equivalent Mass Emissions for a B-Plan; and Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions for a B-Cap.

(B-1) Baseline Unit Emissions and Baseline Facility Emissions

Baseline Unit Emissions shall be determined by the Executive Officer based on the applica7ble 2017 NOx Annual Emissions Reporting data, or another representative year, as approved by the Executive Officer, expressed in pounds per year. Baseline Facility Emissions are the sum of all the Baseline Unit Emissions subject to this rule and shall not include Baseline Unit Emissions for ~~units~~Units that are operational on and after [*DATE OF ADOPTION*].

(B-2) Final Phase Facility BARCT Emission Target

The Final Phase Facility BARCT Emission Target is the Phase II Facility BARCT Emission Target for an I-Plan option with two phases or the Phase III Facility BARCT Emission Target for an I-Plan option with three phases. The Final Phase Facility BARCT Emission Target is used to establish the Phase II or Phase III BARCT Emission Target for a B-Cap. To establish the Final Phase Facility BARCT Emission Target, the owner or operator must select if the basis of the emission target for each ~~unit~~Unit will be based on Table 1 or Table 2 NOx concentration limits. The owner or operator shall only select Table 2 NOx concentration limits if the requirements of subparagraphs (d)(2)(A) and (d)(2)(B) for the Conditional NOx Limits are met or if the ~~unit~~Unit is identified in Attachment D. For all other ~~units~~Units, the owner or operator shall use NOx limits from Table 1 as the basis of the Facility BARCT Emission Target. To calculate the Final Phase Facility BARCT Emission Target for B-Cap, the owner or operator shall use NOx concentration limit of Table 1 for the ~~units~~Units that will be decommissioned.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(B-2.1) The Final Phase Facility BARCT Emission Target for a ~~facility~~Facility complying with NOx emission limits in Table 1, an approved B-Plan or an approved B-Cap shall be calculated using the following equation:

$$\text{Final Phase Facility BARCT Emission Target} = \sum_{i=1}^{N} \left(\frac{C_{\text{Table 1 or Table 2}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions} \right)_i$$

Where:

N = Number of included ~~units~~Units in B-Plan or B-Cap

$C_{\text{Table 1 or Table 2}}$ = The applicable NOx concentration limit for each ~~unit~~Unit i included in B-Plan or B-Cap

C_{Baseline} = Representative NOx Concentration as defined in subdivision (c) for ~~unit~~Unit i included in B-Plan

Baseline Unit Emissions = Baseline Unit Emissions for ~~unit~~Unit i as defined in subdivision (c) and included in the I-Plan, B-Plan or B-Cap as determined pursuant to section (B-1).

(B-3) Calculating Total Facility NOx Emission Reductions

Total Facility NOx Emission Reductions is the total reduction in NOx mass emissions per ~~facility~~Facility or ~~facilities~~Facilities with the same ownership that would have been achieved if all ~~units~~Units met the NOx concentration limits in Table 1 or Table 2 of this rule based on the Baseline Facility Emissions.

(B-3.1) For a ~~facility~~Facility complying with NOx emission limits in Table 1 or Table 2, an approved B-Plan or an approved B-Cap, the Total NOx Emission Reductions is the difference between Baseline Facility Emissions and the Final Phase Facility BARCT Emission

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

Target.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

$$\text{Total Facility NOx Emission Reductions} = \text{Baseline Facility Emissions} - \text{Final Phase Facility BARCT Emission Target}$$

(B-4) Calculating Phase I, Phase II, or Phase III Facility BARCT Emission Target
The Phase I, Phase II, or Phase III Facility BARCT Emission Targets are the total NOx mass emissions per ~~facility~~Facility based on the Total Facility NOx Emission Reductions and the Percent Reduction Target of Phase I, Phase II or Phase III of an I-Plan option in Table 6. ~~For a B-Cap, each phase Facility BARCT Emission Targets shall be reduced by 10 percent.~~

(B-4.1) For the B-Plan and the B-Cap, the Phase I Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Facility Emissions and applying the selected I-Plan Phase I Percent Reduction Target from Table 6 to the Total NOx Emission Reductions.

$$\text{Phase I Facility BARCT Emission Target}_{B-\text{Plan}} = \text{Baseline Emissions} - (\text{Phase I Percent Reduction Target} \times \text{Total Facility NOx Emission Reductions})$$

~~(B-4.2) For the B-Cap, the Phase I Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Facility Emissions and applying the selected I-Plan Phase I Percent Reduction Target from Table 6 to the Total NOx Emission Reductions, less 10 percent.~~

$$\cancel{\text{Phase I Facility BARCT Emission Target}_{B-\text{Cap}} = [\text{Baseline Emissions} - (\text{Phase I Percent Reduction Target} \times \text{Total Facility NOx Emission Reductions})] \times 0.9}$$

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(B-4.3) For the B-Plan and the B-Cap, if Phase II is not final phase, Phase II Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Emissions and applying the selected I-Plan Phase II Percent Reduction Target from Table 6 to the Total NOx Emission Reductions.

$$\text{Phase II Facility BARCT Emission Target}_{B-Plan} = \text{Baseline Emissions} - (\text{Phase II Percent Reduction Target} \times \text{Total NOx Emission Reductions})$$

~~(B-4.4) For a B-Cap, if Phase II is not final phase, Phase II Facility BARCT Emission Target represents the level of NOx emissions that must be achieved based on taking the difference between the Baseline Emissions and applying the selected I-Plan Phase II Percent Reduction Target from Table 6 to the Total NOx Emission Reductions.~~

$$\cancel{\text{Phase II Facility BARCT Emission Target}_{B-Cap} = [\text{Baseline Emissions} - (\text{Phase II Percent Reduction Target} \times \text{Total Facility NOx Emission Reductions})] \times 0.9}$$

(B-4.5) For ~~the~~a B-Plan and the B-Cap, for the final phase, Phase II for the two phase I-Plan or Phase III for the three phase I-Plan, the Phase II or Phase III Final Facility BARCT is the Final Phase Facility BARCT Target as calculated in Section B-2.1.

$$\text{Phase II or Phase III Facility BARCT Emission Target}_{B-Plan} = \text{Final Phase Facility BARCT Emission Target}$$

~~(B-4.6) For a B-Cap, for the final phase, Phase II for the two phase I-Plan or Phase III for the three phase I-Plan, the Phase II or Phase III Final Facility BARCT is the Final Phase Facility BARCT Target as calculated in Section B-2.1.~~

$$\cancel{\text{Phase II or Phase III Facility BARCT Emission Target}_{B-Cap} = (\text{Final Phase Facility BARCT Emission Target}) \times 0.9}$$

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

(B-5) Calculating Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions for a B-Plan

The Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions are the total remaining NOx mass emissions per ~~facility~~Facility that incorporates emission reduction strategies designed to meet Phase I, Phase II, or Phase III target reductions in an I-Plan. The Phase I, Phase II, or Phase III BARCT Equivalent Mass Emissions incorporate the Alternative BARCT NOx Limit for Phase I, Phase II, or Phase III each of the ~~units~~Units included in different phases of the I-Plan. The Alternative BARCT NOx Limits are the ~~unit~~Unit specific NOx concentration limit that are selected by the owner or operator in the B-Plan to achieve the Facility BARCT Emission Targets in the aggregate, where the NOx and CO concentration limits will include the corresponding percent O_2 correction based on the averaging time pursuant to Table 1 or subdivision (k), whichever is applicable. For the B-Plan, decommissioned ~~units~~Units shall be removed from the Baseline Facility Emissions and the Facility BARCT Emission Targets.

(B-5.1) For a B-Plan, the Phase I BARCT Equivalent Mass Emissions for all ~~units~~Units included in a B-Plan shall be calculated using the following equation:

$$\text{Phase I BARCT Equivalent Mass Emissions}_{B-Plan} = \sum_{i=1}^{N} \left(\frac{C_{\text{Phase I Alternative BARCT Emission Limit}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions}\right)_i$$

Where:

N = Number of included ~~units~~Units in B-Plan under Phase I

$C_{\text{Phase I Alternative BARCT Emission Limit}}$ = The applicable Alternative BARCT NOx Limit in an approved B-Plan for ~~unit~~Unit i included in the B-Plan

C_{Baseline} = Representative NOx Concentration as defined in subdivision (c) for ~~unit~~Unit i included in the B-Plan

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

Baseline Unit Emissions = Baseline Unit Emissions for ~~unit~~Unit i as defined in subdivision (c) and included in the B-Plan.

(B-5.2) For a B-Plan, the Phase II and if applicable, Phase III Equivalent Mass Emissions for each ~~unit~~Unit included in a B-Plan shall be calculated using the equation for Section B-5.1, with the use of the Alternative BARCT NOx Limit for Phase II and Phase III, if applicable.

(B-6) Calculating Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions for a B-Cap

The Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions are the total remaining NOx mass emissions per ~~facility~~Facility that incorporates emission reduction strategies. The Phase I, Phase II, and Phase III BARCT B-Cap Annual Emissions must be at or below the respective Phase I, Phase II, or Phase III Facility BARCT Emission Targets in an I-Plan. Under the B-Cap, there are three emission reduction strategies that can be used to meet the Facility BARCT Emission Targets: Establishing an Alternative BARCT NOx Limit, Permanently Decommissioning Units, Replacing Units, and Reducing Throughput for Units. The Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions calculation for the B-Cap acknowledges the three emission reduction strategies for each phase of the I- Plan. The Alternative BARCT NOx Limits are the ~~unit~~Unit specific NOx concentration limits that are selected by the owner or operator in the B-Cap to achieve the Final Phase Facility BARCT Emission Target in the aggregate,
where the NOx concentration limit will include the corresponding percent O_2 correction, CO emission limit, and averaging time per Table1. The emission reductions from Decommission Units shall be incorporated in B-Cap pursuant to section (B-2.2). Other reductions in mass emission reductions to demonstrate that the BARCT B-Cap Annual Emissions include emission reductions from reduced throughput, efficiency, reduced capacity, and any other strategy to reduce mass emissions.

(B-6.1) The Phase I BARCT B-Cap Annual Emissions for each ~~unit~~Unit included in a B-Cap shall be calculated using the following equation ~~where the Unit Throughput Reductions calculated pursuant to Section B-7~~.

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$$\text{Phase I BARCT B} - \text{Cap Annual Emissions}_{B-Cap} = \sum_{i=1}^{N} \left(\frac{C_{\text{Phase I Alternative BARCT Emission Limit}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions} \right)_i + (0_{\text{Decommissioned Units}})_i - (\text{Throughput or Other Reductions})$$

Where:

N = Number of included ~~units~~Units in B-Cap under Phase I

$C_{\text{Phase I Alternative BARCT Emission Limit}}$ = The applicable Alternative BARCT NOx Limit in an approved B-Cap for ~~unit~~Unit i included in the B-Cap

C_{Baseline} = Representative NOx Concentration as defined in subdivision (c) for ~~unit~~Unit i included in the B-Cap

Baseline Unit Emissions = Baseline Unit Emissions as defined in subdivision (c) and for ~~unit~~Unit i included in the B-Cap

Throughput or Other Reductions = Emission reductions occurred from other than reducing the concentration limit.

(B-6.2) For a B-Cap, the emission reductions the Phase II and if applicable, Phase III BARCT B-Cap Annual Emissions for each ~~unit~~Unit included in a B-Cap shall be calculated using the equation for Section B-6.1, with the use of three emission reduction strategies for Phase II and Phase III, if applicable.

(B-7) Emissions Reductions from Decommissioned Unit

For a B-Cap, emission reductions from decommissioned ~~units~~Units can be used to meet a Phase I, Phase II, or Phase III Facility BARCT Emission Target. The

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amount of emission reductions from a permanently decommissioned ~~unit~~Unit shall be determined using the equation below.

Emission Reductions from Permanently Decommissioned Units

$$= \sum_{i=1}^{N} \left(\frac{C_{Table\ 1}}{C_{Baseline}} \times \text{Baseline Unit Emissions}\right)_i$$

Where:

N = Number of permanently decommissioned ~~units~~Units in B-Cap

$C_{Table\ 1}$ = Table 1 NOx concentration limit for ~~unit~~Unit i

$C_{Baseline}$ = Representative NOx Concentration as defined in subdivision (c) for ~~unit~~Unit i included in an approved B-Cap

Baseline Unit Emissions = Baseline Unit Emissions for ~~unit~~Unit i as defined in subdivision (c) and included in an approved B-Cap.

(B-8) Unit Reductions for Conditional NOx and CO Limits in Table 2

An owner or operator of a ~~unit~~Unit in a B-Plan that is demonstrating that the Unit Reduction is less than the thresholds specified in clauses (d)(2)(A)(i) or (d)(2)(A)(ii) shall calculate the Unit Reduction using the following equation:

$$\text{Unit Reduction} = \left(1 - \frac{C_{Table\ 1}}{C_{Baseline}}\right) \times \text{Baseline Unit Emissions}$$

Where:

$C_{Table\ 1}$ = The applicable Table 1 NOx concentration limit the ~~unit~~Unit

$C_{Baseline}$ = Representative NOx Concentration for the ~~unit~~Unit

Baseline Unit Emissions = Baseline Unit Emissions.

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Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

ATTACHMENT C

FACILITIES EMISSIONS – BASELINE AND TARGETS

(C-1) Baseline Facility Emissions

Table C-1 provides the Baseline Mass Emissions for Facilities with six or more ~~units~~Units. Baseline Facility Emissions in Table C-1 are based on 2017 reported emissions for Rule 1109.1 ~~units~~Units. A year other than 2017 was used for ~~units~~Units where the 2017 reported emissions were not representative of normal operations.

TABLE C-1: Baseline Mass Emissions for Facilities with Six or More Units

Facility	Facility ID	Baseline Facility Emissions (2017) (tons/year)
AltAir Paramount, LLC	187165	28
Chevron Products Co.	800030	701
Lunday-Thagard Co. DBA World Oil Refining	800080	26
Phillips 66 Company/Los Angeles Refinery	171109	386
Phillips 66 Co/LA Refinery Wilmington PL	171107	462
Tesoro Refining and Marketing Co., LLC – Carson	174655	636
Tesoro Refining and Marketing Co., LLC – Wilmington	800436	674
Tesoro Refining and Marketing Co., LLC – Sulfur Recovery Plant	151798	8
Tesoro Refining and Marketing Co., LLC, Calciner	174591	261
Torrance Refining Company LLC	181667	899
Ultramar Inc.	800026	248
Valero Wilmington Asphalt Plant	800393	5

Proposed Rule 1109.1 (Cont.) **(Adopted TBD)**

ATTACHMENT D

UNITS THAT QUALIFY FOR CONDITIONAL LIMITS IN B-PLAN AND B-CAP

TABLE D-1: Units That Qualify for Conditional Limits in B-Plan

Facility ID	Device ID	Size (MMBtu/hr)
171109	D429	352
171109	D78	154
174655	D1465	427
174655	D419	52
174655	D532	255
174655	D63	300
181667	D1236	340
181667	D1239	340
181667	D231	60
181667	D232	60
181667	D234	60
181667	D235	60
181667	D950	64
800026	D1550	245
800026	D6	136
800026	D768	110
800030	D159	176
800030	D160	176
800030	D161	176
800030	D643	220
800030	D82	315
800030	D83	315
800030	D84	219
800436	D1122	140
800436	D384	48
800436	D385	24
800436	D388	147
800436	D388	147
800436	D770	63
800436	D777	146

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TABLE D-2: Units That Qualify for Conditional Limits in B-Cap

Facility ID	Device ID	Size (MMBtu/hr)
171107	D220	350
171107	D686	304
171109	D429	352
171109	D78	154
171109	D79	154
174655	D33	252
174655	D419	52
174655	D421	82
174655	D532	255
174655	D539	52
174655	D570	650
181667	D1236	340
181667	D1239	340
181667	D231	60
181667	D232	60
181667	D234	60
181667	D235	60
181667	D920	108
181667	D950	64
800026	D1550	245
800026	D378	128
800026	D429	30
800026	D430	200
800026	D53	68
800026	D6	136
800026	D768	110
800026	D98	57
800030	D453	44
800030	D643	220
800030	D82	315
800030	D83	315
800030	D84	219
800436	D1122	140
800436	D158	204
800436	D250	89
800436	D33	252
800436	D384	48
800436	D385	24
800436	D386	48
800436	D387	71
800436	D388	147
800436	D770	63
800436	D777	146

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Staff Response to Commenter Letter #7:

Response to Comment 7-1:

Please see the Response to Comment 6-19.

Response to Comment 7-2:

Please see the Response to Comment 6-19.

Response to Comment 7-3:

Please refer to response to comment in the Staff Report for PAR 1304.

Response to Comment 7-4:

Staff revised most of the compliance dates to reflect a permit submittal deadline and a deadline to meet the permit limit based on the Permit to Construct or Permit to Operate issuance date. The following are responses to the two specific instances in the comment #7-4:

- Staff retained the 54-month from permit submittal date timeline for the B-Cap to be reduced. A facility complying with a B-Cap has two compliance deadlines, the time to demonstrate the individual unit is meeting the alternative BARCT NOx limits and the timeline when the "cap" is reduced to reflect the schedule in the I-Plan. The "cap" must be reduced to reflect the NOx reduction projects but it would be onerous to reduce the cap per each individual NOx reduction project; therefore, PR 1109.1 will require the cap to be reduced 54 months after the permit submittal deadline. To address the uncertainty for when a permit will be issued, PR 1109.1 includes time extensions for the 54-month deadline if a permit was issued beyond the 18-month assumption that was used for the 54-month requirement. Implementation of time extensions for the emission cap will be implemented in six-month increments.
- In paragraph (f)(7) (formerly (g)(5)), as the intent is to give an incentive for facilities to submit their permit application on time. A late permit submittal will result in a shorter timeframe for the facilities to meet the applicable concentration limits.

Regarding the provisions for the I-Plan (former paragraph (g)(2)), staff moved those provision to a separate subdivision (new subdivision (h)) but retained the former provisions (g)(2)(B) – (G). The plans (I-Plan, B-Plan, and B-Cap) are laid out in three sections:

1. The plan requirements
2. The elements the facility must submit if they elect to comply with a plan (these elements mirror the requirements in the plan)
3. The criteria the South Coast AQMD must review to approve the plan

The language is similar in each section, but they each have a different intent.

Response to Comment 7-5:

Staff concurs and revised the rule to reflect that the first demonstration of compliance for phase I of I-Plan option 4 is 365 days after January 1, 2024. Staff will provide more clarification regarding the demonstration of compliance dates for multi-day rolling averages in the staff report.

Response to Comment 7-6:

Staff concurs with the comment and revised the language to provide more clarification on CO limits. Staff revised the language to add a new term for “Corresponding CO Concentration Limit”, that corresponds to the referenced NOx concentration limit, at the applicable percent oxygen correction and averaging period specified in either Table 1, Table 2, Table 3, or Table 6.

Response to Comment 7-7:

Staff concurs with the comment and moved the compliance schedule requirements, including subparagraphs (d)(8) and (d)(9), to subdivision (f) – Compliance Schedule (formerly subdivision (g)).

Response to Comment 7-8:

Staff clarified the language in the provision regarding when the permit must be surrendered and will require the permits to be surrendered 54 months from the permit submittal date to align the decommissioning with the compliance schedule for the I-Plan. Staff will outline the process for surrendering the permit in the staff report.

Staff concurs with the suggested revision regarding not operating a decommissioned unit within the South Coast AQMD and will reflect that change in the rule.

Response to Comment 7-9:

As mentioned in the comment letter, the purpose of the B-Cap is to provide flexibility to achieve the BARCT emission reduction targets. Attachment B of the rule language provides an equation to calculate the BARCT B-Cap annual emissions in which the different strategies to meet the BARCT emission reduction targets have been considered. The facility selected alternative BARCT NOx limit, decommissioning, throughput, and other reduction strategies have been included to support that flexibility. The rule language has been revised to clarify that those strategies will also be considered when calculating the BARCT B-Cap annual emissions. The “other reductions” term refers to other strategies that an operator can take to reduce the mass emissions. Hence, as long as the facility’s mass emissions is under the facility BARCT emission target at each phase at or before the corresponding compliance dates in the rule, there would be no penalty for the facility under PR 1109.1.

Staff does not agree that a facility complying with a B-Cap should not be required to comply with a NOx concentration limit in a permit. PR 1109.1 will require all units to have an enforceable permit limit upon full rule implementation, in part, to satisfy the AB 617 requirement that the facilities transition to command-and-control regulatory structure and the highest priority should be assigned to those permitted units that have not modified emissions related permit conditions for the greatest period of time. The B-Cap is an alternative compliance option to meeting the NOx concentration limits, which includes the averaging periods specified in Table 1 and Table 2. Allowing a 365-day average for each individual Unit is a weakening of the requirements and would no longer be representative of the averaging periods specified in Table 1 and Table 2. In addition, a 365-day average is inequitable to operators that elect to use a B-Plan, as they are held to the averages specified in Table 1 and Table 2.

In addition, the maximum alternative BARCT NOx concentration limits for the B-Cap will results in all units having some level of NOx emission controls. The maximum alternative BARCT NOx concentration limits are required for the B-Cap because the facility could achieve significant emission reductions from decommissioning units allowing other units not to install any NOx controls, running counter to AB 617.

Response to Comment 7-10:

The BARCT assessment based on third party consultants' report concluded that a 5 ppmv NOx limit, as demonstrated based on a 24-hour average, is technically feasible for boilers and heaters. The Norton Engineering Report noted:

> "*An averaging time of 24 hours allows the operators an appropriate window of time to see a meaningful fluctuation in the NOx emission level, diagnose the problem (if it is not a routine day-to-day event) and take the necessary corrective actions(s) before the NOx BARCT emission limit is exceeded*".

Facilities not complying with a B-Plan or a B-Cap will have to comply the Table 1 NOx emission limit of 5 ppmv as demonstrated based on a 24-hour average which has been shown to be feasible. Hence, a 24-hour averaging time for units complying with a B-plan or B-Cap that can potentially have higher NOx concentrations would be clearly feasible.

Response to Comment 7-11:

- Staff disagrees with this comment as South Coast AQMD rule typically do not impose time limitations on the South Coast AQMD.
- Please see response to comment 6-15 regarding the plan approval process.
- Staff disagrees with the comment about the "mandatory off-ramps" in paragraphs (I)(6). Those provisions are needed to ensure the facilities submit complete plans and respond to information requests in a timely manner.
- Staff concurs and included a provision to clarify the plans are subject to Rule 221

Staff appreciates the comments on the preliminary draft rule language and considered the changes.

Response to Comment 7-12:

Staff concurs with the comment and revised the language in paragraph (e)(3) (formerly paragraph (f)(3)).

Response to Comment 7-13:

- Staff concurs with the change to the time extension language in formerly clause (h)(2)(C)(i)) from 24 month to 18 months since the compliance schedules were all based on the assumption the permit will be issued within 18 months.
- Staff concurs with the suggested revision but will require a complete source test protocol to be submitted at least 60 days (not 90 days) prior to conducting the source test. The 60-day requirement is a standard condition on most permits.
- Staff does not agree with the comment to add "whichever is later" to paragraph (j)(10) (formerly (h)(7)). This paragraph requires the facility to meet the compliance schedule in paragraph (f)(1) or the schedule in an approved I-Plan. The phrase "whichever is later" would not apply in this case as the facility is either complying with the schedule in the approved I-Plan or they are following the schedule in (f)(1), but not both.

Response to Comment 7-14:

- Staff disagrees that the source test schedule in a facilities permit should supersede the source test schedule in PR 1109.1.
- Staff revised the source test timing from “no less than 15 minutes but no longer than 2 hours” to “no less than 60 minutes but no longer than 120 minutes” to reflect the time required in the test method. PR 1109.1 reflects that change in the subparagraphs.
- Staff concurs with the suggestion regarding the source test protocol submission deadline and revised the rule language to reflect the suggested rule language change.
- Staff concurs and will include a 90-day deadline to submit the source test result to the South Coast AQMD.

Response to Comment 7-15:

Please see Response to Comment #6-12.

Response to Comment 7-16:

Please see Response to Comment #6-9.

Response to Comment 7-17:

Please see Response to Comment in the Staff Report for PR 429.1.

Regarding compliance with the Rule 218 Series on CEMS compliance, those requirements will apply once the facility becomes a former RECLAIM facility. Prior to exiting the RECLAIM program and becoming a former RECLAIM facility, the facility will comply with Rule 2012 - Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions(Rule 2012). As facilities migrate from the RECLAIM program to concentration limits, nothing precludes them from certifying the CEMS under Rule 218.2 and 218.3. Those rules were developed for units complying with concentration limits. However, Rule 2012 will be required to demonstrate compliance with RECLAIM until the facility is a Former RECLAIM facility.

Response to Comment 7-18:

Staff revised the rule language to correct the referenced typos. Regarding acronyms, South Coast AQMD relies on the convention to spell the word out the first time it is used and use the acronym from that point forward. The only time an acronym is included as a definition is if additional clarification is required (e.g., parts per million by volume (ppmv) was included as a definition to specify it is corrected to a dry basis at Standard Conditions for the purposes of the rule).

Response to Comment 7-19 – 7-23:

Please see Response to Comment in the Staff Report for PR 429.1.

Response to Comment 7-24 – 7-25:

Please see Response to Comment in the Staff Report for PAR 1304.

Response to Comment 7-26:

Staff appreciates the comments on the rule language and took them under consideration.

Comment Letter 8 (received after close of comment period):

From: Robert Benz
Sent: Friday, October 15, 2021 12:20 PM
To: Michael Krause <MKrause@aqmd.gov>; hfarr@aqmd.gov; ska@aqmd.gov; mmoghani@aqmd.gov; Zoya Banan <zbanan@aqmd.gov>; mmorris@aqmd.gov; gquinn@aqmd.gov
Cc: Patrica Spiritus <PSpiritus@benzaireng.com>
Subject: Question regarding AQMD promotion of Low NOx burners. Request for presentation of the Catamizer

Michael et al:

I was going through documentation pertaining to the upcoming adoption of rule 1109.1 and found in one of the working group meetings, the AQMD was incorporating or otherwise promoting a low NOx burner technology, Clearsign. http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1_wgm17_020421.pdf?sfvrsn=6. You are well aware of my contention that the AQMD is bias against SCR technology, the Rule 1146 mandating substantial source testing requirements of the SCR technology over that of other low NOx technologies, specifically low NOx burners. The inclusion of a Clearsign presentation, a company that purports to have a new type of low NOx burner, seems to confirm the AQMD's bias against SCR technology. I understand that you and your organization has been adamant in refuting my contention. Nevertheless, in response we've designed a SCR system that precludes NH3 emissions, the precursor to PM 2.5/10 which has ostensibly resulted in the SCR specific additional testing requirements in Rule1146.

Is there any way the AQMD could afford our company and opportunity to present this new SCR technology to the AQMD in a forum for the petrochemical industry subjected to the upcoming Rule 1109.1? 8-1

Briefly, our "CataMizer" design incorporates a condensing heat exchanger with its integral ammonia injection grid, SCR catalyst and feedwater economizer, the condensing heat exchanger capturing exhaust heat for preheating combustion air or makeup water while eliminating any ammonia slip emissions. Essentially the Catamizer increases efficiency by capturing the latent heat from exhaust that would normally be lost, the resulting higher efficiency providing additional savings that pays for the emission compliance, eliminating NH3 emissions while reducing carbon emissions.

Given the dubious track record of the particular technology, that the AQMD would include a presentation from Clearsign is baffling unless other technology developments were unknown to your organization. Whereas SCR is generally more expensive than low NOx burners, the current increase in feed stock and natural gas prices combined with the Catamizer's substantial increase in efficiency, the technology provides the proven BARCT NOx compliance with a simple payback through Carbon reduction.

Thank you

Bob

209-602-1019
Robert Benz PE
Benz Air Engineering Co
531 Cypress Ave
Hermosa Beach, CA 90254

From: Robert Benz
Sent: Saturday, October 16, 2021 3:37 PM
To: Michael Krause <MKrause@aqmd.gov>; hfarr@aqmd.gov; ska@aqmd.gov; mmoghani@aqmd.gov; zbanan@aqmd.gov; mmorris@aqmd.gov; gquinn@aqmd.gov
Cc: Patrica Spiritus <PSpiritus@benzaireng.com>; Barbara Baird <BBaird@aqmd.gov>; Wayne Nastri <wnastri@aqmd.gov>; 'alowi@cox.net' <alowi@cox.net>; tony.barboza@latimes.com
Subject: Norton Engineering Consultants - California licensees to do business and practice engineering and conflict of interest statement

Hello Michael

The AQMD released a contract May 3, 2019 to Norton Engineering Consultants (NEC), in business of providing "Engineering Services" specifically to "conduct a review of SCAQMD staff's BARCT analysis as an independent 3rd party validation." As a result, NEC provided the AQMD a report (19-9009-016) prepared by R. S. Todd, E. Lin, J. Zhang, C. A. Steves, J. P.
Norton and report 19-9009-017 prepared by R.S. Todd, J. P. Norton. Could you or team provide 8-2
the following information:

1. The responsible California licensed professional engineer required to practice engineering in the State of California?

2. Section G of the response to RFP P2019-07 - Conflict of Interest provided by NEC?

3. The Corporate status of NEC to conduct business in the state of California?

NEC appears to have a conflict of interest which should had precluded the company's BARCT analysis as an independent 3rd party validation.

Specifically, NEC was employed by Clearsign sometime before January 2017 to provide a report – "DUPLEX™ Technology Evaluation and Cost Comparison to SCR."
https://clearsign.com/wp-content/uploads/2019/10/Duplex-Evaluation-and-SCR-Cost-
Comparison-FINAL-REV1.pdf Clearsign's commissioned report is clearly intended to convey 8-3
the commercially viability of Clearsign's low nox burner design, a design that has changed considerably over the last few years, that to date, has had limited installations, one of which appears to be a failure (World Oil (Page 14 of 50 19-9009-016). Given the NEC's employment by Clearsign, NEC's contention that the so called "CORE burner, considered a leading candidate in the next generation of emerging ULNB technologies," (Page 4 of 8 19-9009-017) seems more influenced by NEC's former, perhaps current benefactor than fact.

Thank you

Bob
209-602-1019
Robert Benz PE
Benz Air Engineering Co
531 Cypress Ave
Hermosa Beach, CA 90254

From: Robert Benz
Sent: Wednesday, October 20, 2021 12:28 PM
To: Michael Krause <MKrause@aqmd.gov>; hfarr@aqmd.gov; ska@aqmd.gov; mmoghani@aqmd.gov; zbanan@aqmd.gov; mmorris@aqmd.gov; gquinn@aqmd.gov
Cc: Patrica Spiritus <PSpiritus@benzaireng.com>; Barbara Baird <BBaird@aqmd.gov>; Wayne Nastri <wnastri@aqmd.gov>; 'alowi@cox.net' <alowi@cox.net>; tony.barboza@latimes.com
Subject: Followup Norton Engineering Consultants - California licensees to do business and practice engineering and conflict of interest statement

Hello Michael

Again I very much appreciated the phone conversation yesterday. During that call I stated that the BARCT analysis for the 1109.1 rule was flawed due to numerous reasons the primary reason that the AQMD was relying on engineering proffered by folks not licensed to provide engineering.

My recollection is that you stated that the AQMD wasn't really interested in attaining engineering analysis for its independent 3rd party review of the district's BARCT, rather you and your team were interested in contracting with some folks that were familiar with oil refinery equipment. Could you please correct my recollection?

I got a hold of the AQMD RFP for "Review of BARCT Technology Assessment and Cost Estimates for Proposed Rule 1109.1." The first paragraph in the statement of work is: "The objective of this RFP is to solicit one engineering contractor with strong technical expertise and experience in NOx equipment and emissions control technologies, as well as installing new or retrofitted applications at existing facilities because refineries and support facilities (e.g., sulfuric acid plants) will be subject to Rule 1109.1." 8-4

Clearly the AQMD issued a contract to an engineering contractor without a state license to practice engineering. Michael, given the illegality of providing engineering without a license to do so, the entire BARCT review must be repeated. Simply stated, there has been no engineering review of the BARCT to date.

Thanks

Bob

From: Robert Benz <RBenz@benzaireng.com>
Sent: Wednesday, October 20, 2021 4:31 PM
To: Barbara Baird <BBaird@aqmd.gov>
Cc: Patrica Spiritus <PSpiritus@benzaireng.com>; Wayne Nastri <wnastri@aqmd.gov>; 'alowi@cox.net' <alowi@cox.net>; tony.barboza@latimes.com; Heather Farr <HFarr@aqmd.gov>; Sarady Ka <SKa@aqmd.gov>; Michael Krause <MKrause@aqmd.gov>; Zoya Banan <ZBanan@aqmd.gov>; Mojtaba Moghani <MMoghani@aqmd.gov>; Gary Quinn <GQuinn@aqmd.gov>; Michael Morris <mmorris@aqmd.gov>
Subject: Request for contracting rules AQMD Norton Engineering Consultants - California licensees to do business and practice engineering and conflict of interest statement

Dear Ms Baird

I am completely flummoxed of your organization's bid and contracting procedures. Perhaps you can enlightening me by first providing or pointing me to where to find the AQMD bid and procurement regulations?

I have found that the AQMD has been contracting engineering consultation services as far back
as 2014 with a company not licensed to provide engineering AND a company that was not
registered to do business in the State of California. The inability of Norton Engineering
Consultants to attain registration to do business was due to their lack of a Professional
Engineering License. There is no listing for the subject company with the California Contractors 8-5
License Board. The procurement of engineering services by the AQMD is unlike any other
California State or local jurisdictions so I am curious to find what if any bids and purchasing
rules the AQMD would allow this illegal activity.

The AQMD reliance on an unlicensed engineer/engineering firm for its BARCT review has limited if any technical credibility and as such all references to the documents 019-9009-016 and 019-9009-017 must be stricken, all payments made to NEC recoup, and the 3rd party review process be repeated with a qualified company and professional engineers registered in the State of California.

Thank you in advance,

Robert Benz PE 25309
Robert Benz PE
209-602-1019 cell
Benz Air Engineering Co
531 Cypress Ave
Hermosa Beach, CA 90254
State Contractors License 746640

Staff Response to Commenter Letter #8:

Response to Comment 8-1:

The BARCT assessment for PR 1109.1 was conducted according to California Health and Safety Code Section Sections 40920.6(a)(1) and 40920.6(a)(2) which includes a robust technology assessment, cost-effectiveness, and incremental cost-effectiveness analysis to establish NOx concentration limits that are representative of BARCT for each class and category of equipment. As part of the technology assessment, a wide range of NOx control technologies are evaluated from burner technologies, after treatment controls such as SCR. By establishing a NOx concentration limit, operators can select the technology or technologies to achieve the NOx concentration limit. PR 1109.1 does not limit or specify the technology that must be used to achieve the NOx concentration limit.

ClearSign™ is one of several technologies that staff identified that could achieve proposed NOx concentration limits. The technology is considered an emerging technology as there are limited installations of the technology at present. Staff does not promote any specific technology, our regulations set emission limits and are technology neutral as to how affected sources plan to meet those standards. In addition, the emission limits in PR 1109.1 where ClearSign™ was one of the technologies evaluated is not effective until ten years after rule adoption. That timeframe is to allow the technology to be further developed and commercialized. On the contrary, emission limits in PR 1109.1 where SCR was identified as one of the technically feasible controls will be effective pursuant to the compliance schedule in the rule. Staff estimates PR 1109.1 will result in the installation of 75 new SCRs and require 25 SCR upgrades. The significant emission reductions that will be achieved in PR 1109.1 rely heavily on NOx reduction capabilities and effectiveness of SCR technology. Staff evaluated the cost-effectiveness of requiring SCRs to achieve low-NOx emission levels for every class and category and required that NOx limit whenever it could be demonstrated to be cost-effective to achieve.

During the rulemaking process, staff invited vendors to make formal presentations and answer questions regarding burner and NOx control technology to the Working Group. With regard to your technology, while there are no further Working Group Meetings planned.

Response to Comment 8-2:

Staff relied on Norton Engineers Consultants to provide their technical expertise on NOx control technologies and specific equipment operated at petroleum refineries. The lead engineer who conducted the review of staff's BARCT assessment and lead author of the final report is Richard Shannon Todd, who is a Chemical Engineer with a California Professional Engineer license (certificate number is CH 6890).

Please see response to comment 8-3 regarding the conflict of interest.

Staff did confirm that Norton Engineering did pay taxes in the state of California. Based on your comment, it was discovered that Norton Engineering had an administrative issue with the California Secretary of State where the Statement of Information was not updated. The purpose of the Statement of Information is to update the Secretary of State of business changes such as new officers or business address. Upon discovering this issue, Norton Engineering completed the Statement of Information, updated their business address, and is now in good standing to conduct business in the state of California. This issue has no bearing on Norton Engineering's technical capabilities to review the South Coast AQMD staff's BARCT analysis. Norton Engineering completed all tasks under Contract Number 19398 satisfactorily. Norton Engineering's work is technically sound and the lapse in updating the Statement of Information does not invalidate their work under Contract Number 19398.

Response to Comment 8-3:

Staff does not view a consultant's prior work with an entity as a conflict of interest in a case such as this, where the work for the other entity was finished substantially before the work for our agency began. The work Norton Engineering did for ClearSign™ was completed more than a year prior to the South Coast AQMD contract to review staff's BARCT assessment. Further, in evaluating the ClearSign™ technology, staff consulted with the vendor as well as several facilities currently using the technology, including World Oil who has an existing unit operating with a ClearSign™ burner.

Response to Comment 8-4:

Please see response to comment 8-2. It should be noted that the California Health and Safety Code does not require a third-party review of staff's BARCT assessment. Due to the size and scope of PR 1109.1, South Coast AQMD contracted with two consultants: Norton Engineering and Fossil Energy Research Corporation (FERCo). This was an additional step taken, supported by the stakeholders in our Working Group, not a legal requirement; therefore, staff disagrees that the review has to be repeated. In addition, as stated above, the reason for Norton's lack of standing to do business in California was an administrative error, now corrected, which has nothing to do with their engineering expertise.

Response to Comment 8-5:

Please see response to comment 8-2.

ATTACHMENT R

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Staff Report

Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations

November 2021

Deputy Executive Officer
Planning, Rule Development, and Area Sources
Sarah Rees

Assistant Deputy Executive Officer
Planning, Rule Development, and Area Sources
Susan Nakamura

Planning and Rules Manager
Planning, Rule Development, and Area Sources
Michael Morris

Author: Isabelle Shine – Air Quality Specialist

Contributors:
Zoya Banan – Air Quality Specialist
Devorlyn Celestine – Air Quality Analysis & Compliance Supervisor
Bhaskar Chandan – Senior Air Quality Engineering Manager
Shah Dabirian – Program Supervisor
Eduardo Esparza – Supervising Air Quality Inspector
Heather Farr – Program Supervisor
Sarady Ka – Air Quality Specialist
Michael Krause – Planning and Rules Manager
Rhonda Laugeson – Supervising Air Quality Inspector
George Lamont – Air Quality Inspector II
Patrick Lee – Air Quality Engineer II
Thomas Lee – Senior Air Quality Engineer
Mika Macfarlane – Air Quality Engineer I
Mojtaba Moghani – Air Quality Specialist
Khang Nguyen – Senior Air Quality Engineer
Barbara Radlein – Program Supervisor
Kendra Reif – Air Quality Specialist
Rafael Reynosa – Senior Enforcement Manager
Thomas Truppi – Air Quality Engineer II
Brian Vlasich – Air Quality Specialist
Tran Vo – Supervising Air Quality Engineer
Uyen-Uyen Vo – Program Supervisor
Yan Yang – Air Quality Engineer II

Reviewed By:
Barbara Baird – Chief Deputy Counsel
Rodolfo Chacon – Program Supervisor
William Wong – Principal Deputy District Counsel

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Control Measure CMB-05 of the Final 2016 Air Quality Management Plan (AQMP) included a five tons per day nitrogen oxides (NOx) emission reduction as soon as feasible but no later than 2025, and a direction to transition the Regional Clean Air Incentives Market (RECLAIM) program to a command-and-control regulatory structure requiring Best Available Retrofit Control Technology (BARCT) as soon as practicable. California State Assembly Bill 617 (AB 617), approved by the Governor on July 26, 2017, requires Air Districts to develop, by January 1, 2019, an expedited schedule for the implementation of BARCT no later than December 31, 2023 for facilities that are in the state greenhouse gas cap-and-trade program.

Petroleum refineries and facilities with related operations to petroleum refineries are currently regulated under the RECLAIM program and are included in the state greenhouse cap-and-trade program. Due to CMB-05 and AB 617, equipment located at petroleum refineries and facilities with related operations to petroleum refineries are required to transition from the RECLAIM program to a command-and-control regulatory structure.

Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations (PR 429.1) is a companion rule to Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR 1109.1). PR 429.1 and PR 1109.1 facilitate the transition of petroleum refineries and facilities related operations to petroleum refineries from the RECLAIM program to a command-and-control regulatory structure.

PR 1109.1 establishes NOx and CO emission limits for NOx emitting combustion equipment at petroleum refineries and facilities with related operations to petroleum refineries. However, PR 1109.1 concentration~~emission~~ limits will not apply during startup, shutdown, commissioning, and certain ~~or catalyst~~ maintenance events. PR 429.1 is needed to establish requirements during startup and shutdown pursuant to U.S. EPA policies to regulate startup, shutdown, and malfunction.

A total of 284 units at sixteen facilities will be affected by PR 429.1. PR 429.1 limits the duration of startup and shutdown events and the frequency of scheduled startups. PR 429.1 also establishes best management practices for startup and shutdown events as well as notification and recordkeeping requirements.

PR 429.1 was developed through a public process. Originally, startup and shutdown provisions for equipment located at petroleum refineries and facilities with related operations to petroleum refineries were included in PR 1109.1. However, as the rulemaking for PR 1109.1 progressed, staff decided to separate startup and shutdown provisions into a separate rulemaking. Staff began the development of PR 429.1 in February 2021, incorporating startup and shutdown provisions that were discussed in prior PR 1109.1 Working Group Meetings. Staff held PR 429.1 Working Group Meetings with PR 1109.1 on April 30, 2021, May 27, 2021, and September 15, 2021. In addition, a Public Workshop was held on September 1, 2021.

CHAPTER 1: BACKGROUND

INTRODUCTION

Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations (PR 429.1) is a companion rule to Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR 1109.1). PR 1109.1 establishes NOx and CO emission limits for combustion equipment at petroleum refineries and facilities with related operations to petroleum refineries. PR 429.1 exempts units from PR 1109.1 NOx and CO concentration~~emission~~ limits and applicable rolling average provisions during startup, shutdown, commissioning and certain~~catalyst~~ maintenance events. PR 429.1 also establishes requirements during startup and shutdown pursuant to U.S. EPA policies to regulate startup, shutdown, and malfunction. PR 429.1 limits the duration of startup and shutdown events and the frequency of scheduled startups. Additionally, PR 429.1 establishes best management practices for startup and shutdown events and notification and recordkeeping requirements.

BACKGROUND

2016 AQMP Control Measure CMB-05

The 2016 Air Quality Management Plan (2016 AQMP) includes control measure CMB-05 which committed to identifying approaches to make the RECLAIM program more effective. During the adoption of the 2016 AQMP, staff was directed to modify CMB-05 to achieve the five tons per day of NOx emission reduction commitment as soon as feasible, but no later than 2025, and to transition the RECLAIM program to a command-and-control regulatory structure requiring Best Available Retrofit Control Technology (BARCT) level controls as soon as practicable. A command-and control regulatory structure establishes emission limits for each individual piece of equipment, in contrast to a market-based program, such as RECLAIM, where an emission target is established in the aggregate. A command-and-control regulatory structure directly regulates an industry with requirements that state what is permitted and what is prohibited. The ‘command’ is the presentation of standards that must be complied with by facilities. The ‘control’ part signifies the negative sanctions that may result from non-compliance. In this instance, NOx landing rules prescribe emission limits and other requirements for specific equipment or industries.

Startup and Shutdown

Under the RECLAIM program, facilities are required to hold sufficient RECLAIM Trading Credits (RTCs) to reconcile actual emissions at the end of each annual compliance cycle, including the emissions that occur during startup and shutdown. A unit and/or associated control equipment is not operating under steady-state conditions during startup or shutdown, which may result in greater emissions. For example, during startup and shutdown of combustion equipment, the temperature of the unit and/or associated controls is in transition and requires the addition of excess air. This process results in increased NOx formation.

Under a command-and-control regulatory structure, an owner or operator is required to meet emission limits on each individual piece of equipment on a continuous basis. Consequently, units that can otherwise meet lower NOx concentration~~emission~~ limits during steady-state conditions, may be unable to do so during periods of startup and shutdown. Therefore, provisions are needed to exclude emissions that occur during startup and shutdown from compliance determination with the BARCT concentration~~emission~~ limit(s). PR 1109.1 and PR 429.1 work together to regulate NOx emitting combustion equipment at petroleum refineries and facilities with related operations to petroleum refineries during steady-state conditions, and during startup and shutdown, respectively. ~~PR 1109.1 excludes startup and shutdown events from the BARCT emission limits established under the rule. Whereas, PR 429.1 establishes requirements during startup and shutdown, such as limiting the duration of startup and shutdown events and the frequency of scheduled startups.~~

Originally, startup and shutdown provisions for equipment located at petroleum refineries and facilities with related operations to petroleum refineries were included in PR 1109.1. However, as the rulemaking for PR 1109.1 progressed, staff decided to separate startup and shutdown provisions into a separate rulemaking, as the startup and shutdown requirements in Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries (Rule 1109), are contained in Rule 429 – Start-Up and Shutdown Exemption Provisions for Oxides of Nitrogen (Rule 429).

U.S. EPA POLICY ON STARTUP, SHUTDOWN, AND MALFUNCTION (SSM)

U.S. EPA issued startup, shutdown, and malfunction policies in 2015 and 2020, which provided differing guidance on the requirements necessary for State Implementation Plan (SIP) approval. The 2015 policy stated that an emission limitation must be applicable to the source continuously to be permissible in a SIP, whereas the 2020 policy stated that a SIP may contain exemption provisions to emission limits during SSM events if the SIP is composed of numerous planning requirements that collectively protect the National Ambient Air Quality Standards (NAAQS). PR 429.1 is designed to meet the requirements for startup and shutdown provisions described in the 2015 SSM SIP Policy.

On September 30, 2021, U.S. EPA issued a guidance memorandum to withdraw the 2020 SSM SIP Policy and reinstate the 2015 SSM SIP Policy[1].

2015 Startup, Shutdown, and Malfunction State Implementation Plan Policy

In 2015, U.S. EPA issued a SSM SIP Policy which stated that exemptions from emission limitations during startup and shutdown events and affirmative defense provisions were inconsistent with the federal Clean Air Act (CAA)[2]. U.S. EPA asserted that an emission limitation must be applicable to the source continuously to be permissible in a SIP pursuant to CAA section 302(k). U.S. EPA's 2015 SSM SIP Policy stated that SIP emission limitations do not need to be numerical in format, do not have to apply the same limitation (e.g. numerical level) at all times, and may include alternative numerical limitations, other technological control requirements, or

[1] 2021 SSM Guidance Memorandum | U.S. EPA
[2] 2015 SSM Policy | U.S. EPA

work practice requirements during startup and shutdown events, so long as those components of the emission limitations meet applicable federal CAA requirements.

U.S. EPA issued SIP calls to 36 states with SIP provisions that were substantially inadequate in meeting the CAA requirements. Subsequently, petitions for review were filed with the D.C. Circuit Court of Appeals regarding U.S. EPA's 2015 SSM Policy. In 2017, the D.C. Circuit postponed oral arguments at the request of U.S. EPA because U.S. EPA was reviewing the 2015 SSM SIP Policy. After U.S. EPA took two regional actions that deviated from their 2015 SSM SIP Policy, they reviewed their policy and concluded SSM provisions may be permissible in SIPs in certain circumstances which are outlined in U.S. EPA's October 9, 2020 Memorandum Inclusion of Provisions Governing Periods of Startup, Shutdown, and Malfunctions in State Implementation Plans (2020 SSM SIP Policy)[3].

2020 Startup, Shutdown, and Malfunction State Implementation Plan Policy

The 2020 SSM SIP Policy states that a SIP may contain exemption provisions to emission limits during SSM events if the SIP is composed of numerous planning requirements that collectively protect the National Ambient Air Quality Standards (NAAQS). U.S. EPA expects that an in-depth analysis of a SIP will be necessary to determine whether a specific exemption provision is permissible. The 2020 SSM SIP Policy recognizes that a state may be able to demonstrate that a SIP which contains other control measures during SSM events, such as general duty requirements, work practice standards, best management practices, or alternative emission limits, is protective of the NAAQS. U.S. EPA will also consider if the SSM provision in the rule, when considered alongside other factors, will attain and maintain the NAAQS. Such considerations include requirements for sources to use best practicable air pollution control practices to minimize emissions and limitations to the duration and severity of SSM events.

SOUTH COAST AQMD STARTUP AND SHUTDOWN PERMIT CONDITIONS

South Coast AQMD permits often contain startup and shutdown requirements. The permit conditions are tailored for specific equipment and may include limits to the frequency and duration of startups and shutdowns, in addition to mass emission limits, monitoring, and recordkeeping requirements for startups and shutdowns. Staff initially sought to rely on permit conditions to limit startup and shutdown events. However, U.S. EPA recommended that startup and shutdown be included in rules to facilitate enforceability and ensure SIP approval. PR 429.1 will include general restrictions for startup and shutdown events while permit conditions will provide tailored requirements and remain in effect after PR 429.1 is adopted. If a permit contains more stringent requirements than PR 429.1, the more stringent permit requirements will continue to be applicable.

[3] 2020 SSM Policy | U.S. EPA

NOx CONCENTRATION AND MASS EMISSIONS DURING STARTUP AND SHUTDOWN

NOx mass emissions for major NOx sources such as process heaters and boilers are calculated using a certified Continuous Emissions Monitoring System (CEMS). CEMS measures several variables to calculate the mass flow rate of NOx in units of lb/hour. Standard gas conditions are defined as a gas temperature of 60°F and a gas pressure of 760 mm Hg (14.7 pounds per square inch) absolute. Table 1-1 contains the measured variables generally used to determine NOx mass emissions.

TABLE 1-1
NOx MASS EMISSIONS VARIABLES FOR CEMS CALCULATIONS

Measured Variables
1. Stack NOx concentration and exhaust flow rate; OR
2. Stack NOx concentration, O2 concentrations, and fuel rate

From the measured variables, an hourly mass emissions flow rate is calculated and total daily mass emissions from each source is reported. Fuel flow measuring devices can be used for approximating stack flow in conjunction with F-factors. Each CEMS is required to conduct semi-annual or annual assessment test of each CEMS known as a Relative Accuracy Test Audit (RATA).

Fundamentally, NOx mass emissions are calculated from the measured NOx concentration and measured stack gas volumetric flow rate. Alternatively, the stack gas volumetric flow rate can also be approximated from measured fuel flow rate for each type of fuel used. Below are general equations to determine NOx mass emissions.

NOx mass emissions are calculated according to the following:

lbs/hour = (Stack Gas Concentration) x (Stack Gas Volumetric Flow Rate) x (1.195×10^{-7})

- Stack Gas NOx concentration as measured in ppmvd
- Stack Gas Volumetric Flow Rate in dscfh

Alternatively, determination of stack flow rate from fuel flow is based on the following equation:

Stack Flow Rate = [20.9/(20.9 - O_2 concentration)] x (dry F-factor x Fuel flow rate x HHV)

- O_2 Concentration is measured at the stack in percent
- Oxygen based dry F-factor of the fuel in dscf/MMBtu
- Fuel flow rate*
- Higher heating value of fuel, HHV*

*The product of the fuel flow rate and HHV in MMBTU/hr

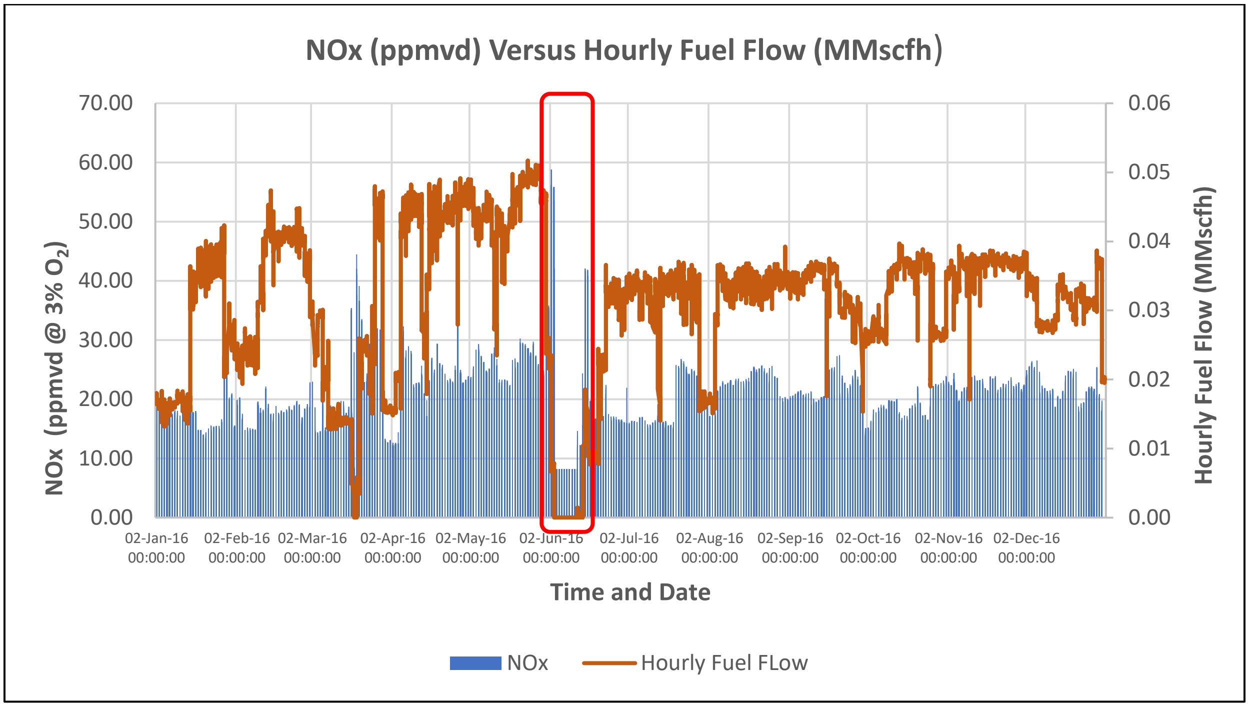
For any given NOx stationary combustion source such as process heaters or boilers with a low NOx permit limit of 5 ppmvd or less, it is understood and accepted that these low NOx levels are steady-state, controlled limits that are made possible by proper combustion and control technology operation. Startup and shutdown emissions on the other hand, are not steady-state emissions and fluctuate more compared to emissions under normal controlled operations. NOx emissions from refinery equipment are not well characterized during periods of startup and shutdown. These periods serve as transitional periods to help thermally stabilize the unit prior to and after full operation. For example, during startup and shutdown of combustion equipment, the temperature of the unit and/or associated controls is in transition and requires the addition of excess air. This process results in increased NOx formation. While NOx concentration can be higher than normal, this does not necessarily translate to higher NOx mass emissions since fuel rates are typically lower than normal operation since the units are not operating at full operational capacity. As mentioned earlier, a lower fuel rate will result in lower stack volumetric flow rate which is one of the factors in determining overall NOx mass emissions.

Below are two examples of startup/shutdown periods and associated NOx emissions for units equipped with NOx controls. The first example is of a process heater with low-NOx burners (LNB) only and the second example is of a boiler with a LNB and selective catalytic reduction (SCR).

Example One: 82 MMBtu/hr Process Heater with LNB

Figure 1-1 is an example of CEMS data that staff analyzed for a 82 MMBtu/hr process heater at a refinery equipped with LNB. To show relationship between NOx and fuel, the primary y-axis represents NOx emissions in ppmvd and secondary y-axis represents fuel flow in MMscfh. Based on CEMS data, staff identified several periods as potential startup/shutdown scenarios – typically characterized by the ramping down and up of fuel. According to the data there are instances of NOx excursions, but the corresponding fuel usage was dramatically lower, so overall NOx mass emissions was also lower. On average fuel usage can be up to 80% less than normal operation during these startup/shutdown periods. NOx excursions during these periods only occurred for short durations where the unit was in a transitional state. This excursion is expected since manufacturer guarantees for combustion control equipment performance are at steady-state operations and not transitional or startup/shutdown periods.

Figure 1-1 – CEMS and fuel data for 82 MMBtu/hr process heater at a refinery with low NOx burners



Please note the data analyzed by staff was raw unaudited CEMS data that was not annotated with events specifying startup or shutdown periods. Table 1-2 contains a sample NOx emissions calculation comparison based on the process heater in Example 1.

TABLE 1-2
NOx EMISSION CALCULATION FOR 82 MMBTU/HR PROCESS HEATER WITH LNB

	Steady-State Operation	Startup/Shutdown
NOx Concentration @ 3% O2 (ppmvd)	14.7	55.8
Hourly Fuel Flow (MMscfh)	0.03807	0.00738
HHV(Btu/scf)	1,294	1,220
Measured O_2 (%)	5.3	10.1
Calculated Stack Flow rate (dscfh)	574,853	151,760
NOx Emissions (lb/hr)	1.01	1.0009

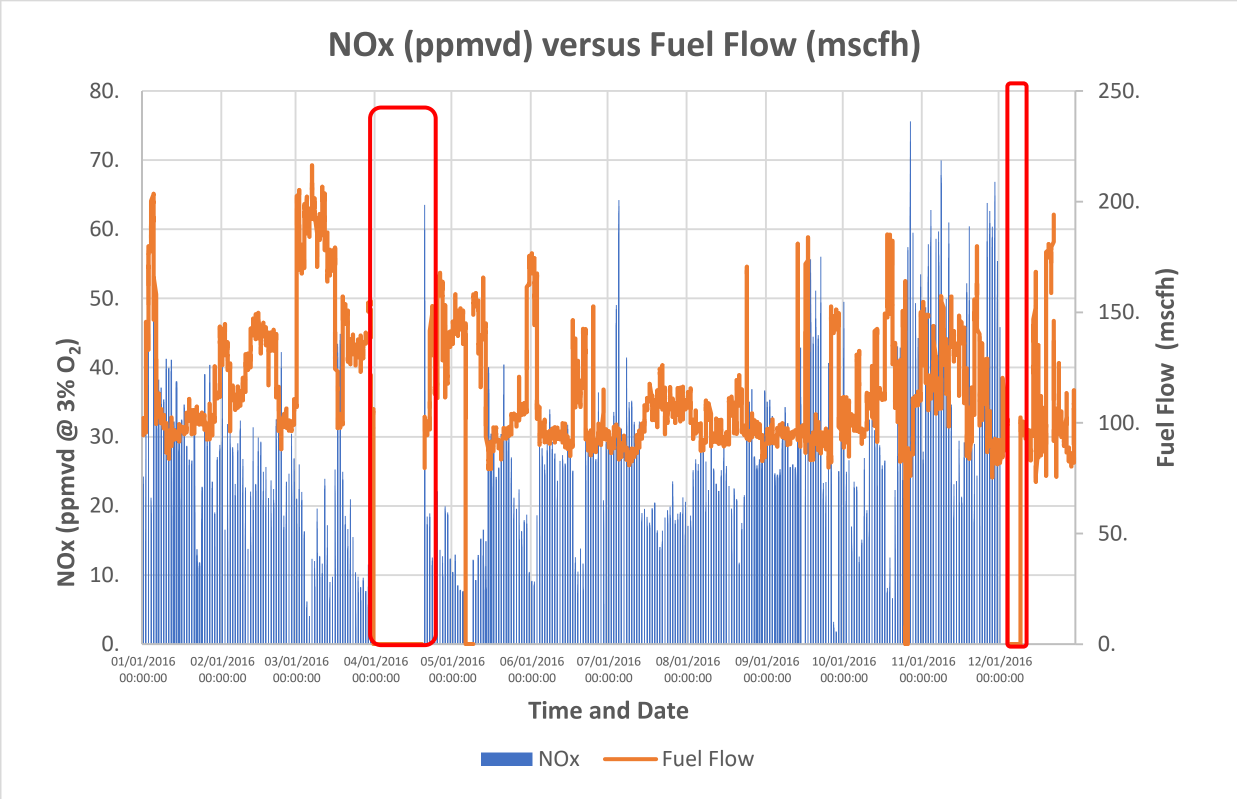
Based on the CEMS data for the example process heater with LNB only, the NOx concentration calculation during a potential startup/shutdown period does not necessarily equate to a higher mass emission of NOx. Other measured variables, such as flow rate also contribute to the overall calculation. In the example above, there was nearly four times more NOx based on concentration in ppmvd during the potential startup/shutdown period but the corresponding mass emission rate did not translate to four times more NOx mass emissions.

Example Two: 304 MMBtu/hr Boiler with LNB and SCR

NOx emissions for units equipped with NOx post-combustion control equipment such as SCR can potentially show a higher deviation in overall NOx mass emissions during startup/shutdown periods. This is primarily due to the SCR not being in optimal operation. Modern SCR designs can achieve up to 95% reduction and achieve very low NOx concentrations, however there is an optimal temperature range where the high NOx reduction can occur. If the unit is not at optimal temperature, the SCR cannot achieve maximum NOx reductions – general temperature window is approximately 550 ºF to 1000 ºF and will vary based on catalyst type and manufacturer. During startup periods the temperature of flue gas leaving the unit may not be high enough for optimal SCR performance and will require time to reach optimal temperature. Furthermore, older SCRs (installed in the early to mid-1990's) do not perform as well as modern SCR design and removal efficiencies can be lower in the 50 to 60% range.

Figure 1-2 is an example of CEMS data for a 304 MMBtu/hr boiler at a refinery with first generation LNB and an older SCR for NOx control. The boiler currently has a 0.015 lb/MMBtu NOx limit under RECLAIM. Similar to Example One above, the relationship between NOx and fuel is shown. The primary y-axis represents NOx emissions in ppmvd and secondary y-axis represents fuel flow in mscfh. Based on CEMS data, staff identified two periods as potential start-up/shutdown scenarios which are highlighted by the red boxes.

Figure 1-2 – CEMS and fuel data for 304 MMBtu/hr Boiler at a refinery with LNB and SCR



Based on the CEMS data that staff analyzed for the boiler, NOx concentrations can be up to three times as high during startup; this is expected since the SCR is not at optimal temperature for maximum NOx removal efficiency. However, this high NOx mass emission rate event only occurred for a limited amount of hours and is highlighted in yellow in Table 1-3 below. The assumption can be made that once the SCR reached optimal temperature and its proper operation was achieved, the NOx mass emission dropped by approximately 50% and if it was a modern or upgraded SCR, the reduction can be even greater within a short period of time.

TABLE 1-3
STARTUP PERIOD AND STEADY-STATE CEMS DATA FOR BOILER

Date/Time	NOx (ppmvd)	NOx @3% (ppmvd)	O2 (%)	Stack Flow (mscfh)	Fuel Flow (mscfh)	NOx (lbs/hr)	HHV 1 (Btu/scf)
STARTUP							
04/20/2016 12:59:59	9.598	36.712	6.825	1481.349	79.521	1.7	1423.098
04/20/2016 13:59:59	21.129	49.717	5.353	1718.691	101.182	4.4	1435.702
04/20/2016 14:59:59	29.847	63.514	5.128	1768.25	102.788	6.31	1473.157
04/20/2016 15:59:59	25.811	59.907	5.321	1679.679	97.276	5.18	1460.168
04/20/2016 16:59:59	12.956	29.501	5.277	1702.361	100.359	2.63	1438.495
04/20/2016 17:59:59	10.723	24.491	5.284	1698.026	102.195	2.18	1408.337
04/20/2016 18:59:59	10.726	24.23	5.259	1695.41	102.184	2.17	1408.552
04/20/2016 19:59:59	10.095	23.552	5.333	1661.187	101.33	2.01	1385.474
04/20/2016 20:59:59	7.772	20.083	5.584	1610.468	96.606	1.5	1385.709
04/20/2016 21:59:59	7.003	18.369	5.623	1602.834	97.491	1.34	1363.175
04/20/2016 22:59:59	6.758	17.679	5.616	1603.367	97.569	1.29	1363.398
12/09/2016 09:59:59	0.115	-79.615	21.026	0.	0.	0.	1278.705
12/09/2016 10:59:59	4.432	38.116	18.907	0.	0.	0.	1304.594
12/09/2016 11:59:59	20.721	55.371	14.264	0.	0.	0.	1309.392
12/09/2016 12:59:59	16.299	33.094	12.135	0.	0.	0.	1298.104
12/09/2016 13:59:59	47.855	52.797	4.685	1754.493	88.013	10.19	1301.049
12/09/2016 14:59:59	18.715	20.73	4.75	2043.689	101.386	4.58	1308.846
12/09/2016 15:59:59	11.314	12.767	5.048	1950.424	95.915	2.63	1296.179
12/09/2016 16:59:59	9.344	10.322	4.706	2047.318	102.413	2.29	1301.559

For comparison, the Table 1-4 below shows the typical NOx concentrations and NOx mass emissions during a period of normal steady-state operations for the boiler in Example 2.

TABLE 1-4
STEADY-STATE CEMS DATA FOR BOILER

Date/Time	NOx (ppmvd)	NOx @3% (ppmvd)	O2 (%)	Stack Flow (mscfh)	Fuel Flow (mscfh)	NOx (lbs/hr)	HHV 1 (Btu/scf)
STEADY-STATE							
09/18/2016 23:59:59	9.053	12.098	7.531	2280.177	85.121	2.47	1482.556
09/19/2016 00:59:59	9.202	12.271	7.502	2307.62	83.744	2.54	1541.083
09/19/2016 01:59:59	9.385	12.541	7.53	2318.878	83.332	2.6	1556.373
09/19/2016 02:59:59	9.106	12.166	7.527	2301.028	83.773	2.5	1520.396
09/19/2016 03:59:59	9.964	13.071	7.279	2294.182	87.997	2.74	1458.136
09/19/2016 04:59:59	10.639	13.766	7.089	2339.046	89.019	2.98	1511.721
09/19/2016 05:59:59	10.688	13.806	7.065	2311.644	89.495	2.95	1480.086
09/19/2016 06:59:59	10.701	13.815	7.057	2308.005	90.352	2.95	1451.861
09/19/2016 07:59:59	9.951	12.509	6.681	2362.826	95.677	2.81	1413.167
09/19/2016 08:59:59	9.533	12.254	6.997	2311.638	91.588	2.64	1411.058
09/19/2016 09:59:59	9.585	12.153	6.804	2402.644	93.827	2.75	1451.252
09/19/2016 10:59:59	9.451	11.988	6.809	2406.33	93.128	2.72	1463.91
09/19/2016 11:59:59	9.413	11.999	6.879	2400.68	92.648	2.7	1460.66
09/19/2016 12:59:59	10.827	13.748	6.824	2413.017	92.247	3.12	1480.524
09/19/2016 13:59:59	10.176	12.907	6.809	2398.985	93.444	2.92	1454.725
09/19/2016 14:59:59	9.626	12.206	6.805	2375.061	95.558	2.73	1409.008

REGULATORY HISTORY

Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries

The South Coast AQMD adopted the Rule 1109 on November 1, 1985. The rule was last amended on August 5, 1988. Rule 1109 is applicable to boilers and process heaters in petroleum refineries and established refinery-wide NOx emission limits.

Rule 429 – Start-Up and Shutdown Exemption Provisions for Oxides of Nitrogen

South Coast AQMD Rule 429 was adopted on May 5, 1989 and last amended on December 21, 1990. Rule 429 applies to equipment subject to Rule 1109, Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines (Rule 1134), Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters (Rule 1146), and Rule 1159 – Nitric Acid Units - Oxides of Nitrogen (Rule 1159). Rule 429 established an exemption from NOx emission limits during scheduled startup and shutdown events, as well as limitations to the number and duration of scheduled startup and shutdown events and notification and recordkeeping requirements.

RECLAIM Program

The Regional Clean Air Incentives Market (RECLAIM) program is a market-based program that was adopted on October 15, 1993 and applies to facilities with annual emissions four tons per year or more of NOx or SOx. RECLAIM was designed to achieve emission reductions in aggregate equivalent to what would occur under a command-and-control regulatory approach. All petroleum refineries and facilities with related operations to petroleum refineries were transitioned into the RECLAIM program, where they are currently regulated. As listed in Rule 2001– Applicability, subdivision (j), facilities subject to NOx RECLAIM are exempted from meeting the requirements of Rules 429 and 1109.

Under the RECLAIM program, an owner or operator is required to hold RTCs at the end of each annual compliance cycle that are representative of all actual emissions, except for breakdowns which meet specific criteria under Rule 2004 – Requirements. Emissions that occur under typical operations, as well as emissions that occur from startups and shutdowns, are counted toward the actual emissions that are required to be reconciled. PR 1109.1 and PR 429.1 are being adopted to transition petroleum refineries and facilities with related operations to petroleum refineries to a command-and-control regulatory structure. In a command-and-control regulatory structure, an owner or operator is required to meet emission limits on each individual piece of equipment on a continuous basis. PR 1109.1 concentration~~emission~~ limits do not apply during startup, shutdown, commissioning, and certain~~catalyst~~ maintenance events, therefore, PR 429.1 is needed to establish requirements during startup and shutdown pursuant to U.S. EPA policies to regulate startup, shutdown, and malfunction.

AFFECTED FACILITIES AND EQUIPMENT

PR 429.1 applies to equipment regulated under PR 1109.1. Based on permitting data and facility surveys, staff identified 284 units at 16 facilities that meet the applicability requirements of PR 429.1. Table 1-5 contains the equipment affected by PR 429.1.

TABLE 1-5
PR 429.1 AFFECTED EQUIPMENT

Equipment Type	Number of Units
Boilers and Process Heaters without NOx Post-Combustion Control Equipment	162
Boilers and Process Heaters with NOx Post-Combustion Control Equipment	59
FCCUs	5
Flares	1
Gas Turbines	12
Petroleum Coke Calciners	1
Sulfur Recovery Unit/Tail Gas (SRU/TG) Incinerators	16
Steam Methane Reformer Heaters	11
Steam Methane Reformer with Gas Turbine	2
Sulfuric Acid Furnaces	2
Vapor Incinerators without NOx Post-Combustion Control Equipment or Castable Refractory	11
Vapor Incinerators with NOx Post-Combustion Control Equipment	0*
Vapor Incinerators with Castable Refractory	2

* There is a proposed SCR retrofit project

PUBLIC PROCESS

The development of PR 429.1 was conducted through a public process. Working Group Meetings included representatives from affected facilities, environmental and community groups, other agencies, consultants, and interested parties. The purpose of the Working Group Meetings was to discuss details of proposed rule and to listen to concerns and issues with the objective to build consensus and resolve key issues.

In February 2021, staff decided it would be more appropriate to separate startup and shutdown provisions in PR 1109.1 into a separate rulemaking, as the startup and shutdown requirements in Rule 1109, are contained in Rule 429. Since PR 429.1 is directly related to the implementation of PR 1109.1, all PR 429.1 Working Group Meetings were held during PR 1109.1 Working Group Meetings. Staff began the development of PR 429.1 in February 2021, incorporating startup and shutdown provisions that were discussed in prior PR 1109.1 Working Group M~~m~~eetings. Staff held PR 429.1 Working Group Meetings remotely with PR 1109.1 on April 30, 2021, May 27, 2021, and September 15, 2021.

In addition, one Public Workshop was held on September 1, 2021. The purpose of the Public Workshop was to present the proposed rule language to the general public and to stakeholders and to solicit comments.

On September 10, 2021, staff held a joint study session with PR 1109.1 and associated rulemakings for stakeholders interested in better understanding the requirements and implementation of the proposed rules and proposed amended rules.

CHAPTER 2: SUMMARY OF PROPOSAL

INTRODUCTION

PROPOSED RULE 429.1

INTRODUCTION

PR 429.1 will establish requirements during periods of startup and shutdown. The proposed rule will be applicable to petroleum refineries and facilities with related operations to petroleum refineries that are subject to PR 1109.1. The following provides a discussion of provisions under PR 429.1.

PROPOSED RULE 429.1

Subdivision (a) – Purpose

The purpose of this rule is to provide an exemption from Rule 1109.1 oxides of nitrogen (NOx) and carbon monoxide (CO) concentration~~emission~~ limits and applicable rolling average provisions during startup, shutdown, commissioning, and certain maintenance events and establish requirements during startup, shutdown, and certain maintenance events to limit NOx and CO emissions. PR 429.1 is needed to establish requirements during startup and shutdown pursuant to U.S. EPA policies to regulate startup, shutdown, and malfunction.

Subdivision (b) – Applicability

PR 429.1 applies to an owner or operator of units at petroleum refineries and facilities with related operations to petroleum refineries. These facilities are subject to PR 1109.1.

Subdivision (c) – Definitions

PR 429.1 incorporates definitions from PR 1109.1 and source-specific rules to define types of facilities, equipment, and other rule terms. New or modified definitions added to PR 429.1 include:

- CASTABLE REFRACTORY means refractory that is made by curing liquid material that has been poured into a mold.

  This proposed definition describes a type of refractory and is used to distinguish the vapor incinerator categories in Table 1 (Table 2-1 in Staff Report). Castable refractory is harder than other types of refractory, such as a ceramic fiber catalyst, and takes longer to heat up as a result.

- CATALYST MAINTENANCE means conditioning, repairing, or replacing the catalyst in NOx post-combustion control equipment associated with a unit which has a bypass stack or duct that exists prior to [*Date of Adoption*].

  This proposed definition describes the type of maintenance activities that are allowed pursuant to paragraph (d)(7). This definition specifies that only units which have a bypass stack or duct that exists prior to [*Date of Adoption*] may elect to use a bypass for the maintenance activities listed in the definition.

- CATALYST REGENERATION ACTIVITIES means the procedure where air or steam is used to remove coke from the catalyst of a unit or the conditioning of catalyst prior to the startup of a unit.

  This proposed definition describes a maintenance activity that is exempt from paragraph (d)(2) of PR 429.1 in subparagraph (g)(1)(B). Staff received comments from operators which described times when a unit that contains catalyst may be required to undergo a catalyst regeneration. For example, a semi-regenerative rheniformer unit is a fixed-bed catalyst reactor system which accumulates carbon on the catalyst during the unit's operation. Over time, the carbon buildup reduces the catalyst's effectiveness and it requires that the unit be shutdown and the catalyst undergo a procedure to restore its activity. During this procedure, a unit, such as a furnace, may be used as a heat source to burn the carbon off of the catalyst.

In addition to regeneration activities, other catalyst systems may require steps to condition catalyst. For example, the sulfiding of a catalyst system requires the injection of a sulfur-containing reagent to temporarily reduce catalyst activity in preparation for the introduction of hydrocarbon feed to the unit. During the sulfiding of a catalyst system, a unit, such as a furnace, may be used as a heat source to assist with the decomposition of the sulfur-containing reagent.

Staff acknowledges that the activities in the regeneration or conditioning of catalyst systems as described in the preceding paragraphs and other similar activities constitute a unique occurrence where a unit, such as a furnace, is operated under abnormal conditions. The time to complete catalyst regeneration~~ or catalyst conditioning~~ activities will not be counted towards PR 429.1 time allowances of a startup or shutdown.

- COMMISSIONING means the first commissioning of a unit, the first commissioning of NOx post-combustion control equipment, or electrical testing associated with upgrades or repairs of cogeneration gas turbines as required by North American Electric Reliability Corporation standards.

  This proposed definition provides clarification on a type of activity that is exempt from PR 1109.1 NOx and CO <u>concentration</u>~~emission~~ limits and applicable rolling average provisions pursuant to paragraph (d)(1) and exempt from the requirements in paragraph (d)(2).

- <u>FEED RATE means the total input of any petroleum derivative feedstock stream to a process unit.</u>

  <u>This proposed definition provides clarification for compliance determination with subparagraph (d)(7)(C). The feed rate includes the total input of any petroleum derivative feedstock, which includes fresh feed and recycled feed.</u>

- MINIMUM OPERATING TEMPERATURE means the minimum operating temperature specified by the manufacturer, unless otherwise defined in the South Coast AQMD Permit to Construct or Permit to Operate.

  This proposed definition provides clarification on the temperature described for compliance determination in various PR 429.1 requirements.

- NEW FACILITY means a facility that begins operation after [*Date of Adoption*].

  This definition describes a type of facility that PR 429.1 is applicable to.

- NOx POST-COMBUSTION CONTROL EQUIPMENT means air pollution control equipment which eliminates, reduces, or controls the issuance of NOx after combustion.

  This definition is modified from the Rule 102 – Definition of Terms definition of CONTROL EQUIPMENT and made specific to NOx and post-combustion control equipment.

- REFRACTORY DRYOUT means the initial application of heat under controlled rates to safely remove water from refractory lining as part of the curing process prior to placing the unit in service.

  This proposed definition describes a process that is exempt from PR 429.1 from paragraph (d)(2) of PR 429.1 in subparagraph (g)(1)(A).[4]

- SCHEDULED STARTUP means a planned startup that is specified by January 1 of each year.

  This definition was modified from the definition of A SCHEDULED START-UP AND SHUTDOWN PAIR in Rule 429. Scheduled startup events include, but are not limited to, those planned for maintenance, testing, tuning, or construction. A startup is only considered a scheduled startup if it is specified by January 1 each year. Scheduled startups do not include change in status due to demand loads, unplanned maintenance, breakdowns, malfunctions, or other events not scheduled prior to January 1 for the upcoming calendar year.

- SHUTDOWN means the time period that begins when an operator reduces load or heat input, and flue gas temperatures fall below the minimum operating temperature of the NOx post-combustion control equipment, if applicable, and which ends in a period of zero fuel flow or zero feedstock, or when combustion/circulation air flow ends if the unit does not use fuel for combustion.

  This proposed definition is from Rule 1134 and was modified to apply to all equipment types subject to PR 429.1.

- STABLE CONDITIONS means that the fuel flow, fuel composition, or feedstock to a unit, or the combustion/circulation air if the unit does not use fuel for combustion, is consistent and allows for normal operations.

  This proposed definition provides clarification for compliance determination under subparagraph (d)(2)(A), as well as the definition of startup. For example, a stakeholder expressed concern that during the startup of a hydrogen reformer furnace, there is an adjustment period where the fuel balance fluctuates and is unstable. Once the fuel balance normalizes, the unit is considered to be under stable conditions. A unit may stabilize and destabilize multiple times during a complex startup procedure. Stable conditions are only determined after all startup procedures for a unit are complete.

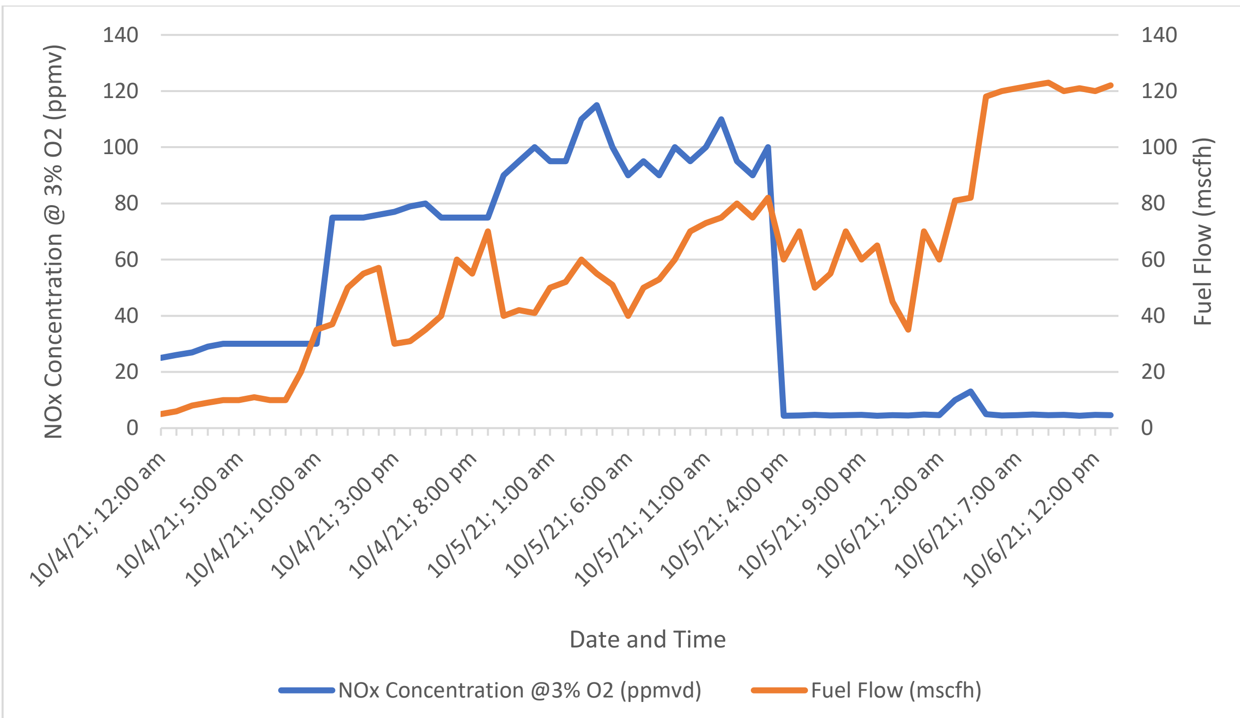
  Staff provides an example of when evaluating the time stable conditions are met is essential for determining compliance with the startup and shutdown duration limits specified in paragraph (d)(2) (Figure 2-1). This example was created by staff for clarification purposes and is not based on actual CEMS data. This example is for a process heater equipped with NOx post-combustion control equipment, which has a startup duration limit of 48 hours.

  In this example, startup begins on October 4, 2021, at 12:00 am. On October 5, 2021, at 4:00 pm the flue gas temperature reaches the minimum operating temperature of the NOx post-combustion control equipment, the NOx post-combustion equipment begins operating, and the Rule 1109.1 NOx concentration limit of 5 ppmv is met. The process heater took 40 hours

[4] https://brimstone-sts.com/wp-content/uploads/2015/11/04V11-Jenkins-Considerations-for-Refractory-Dryouts.pdf

to reach the minimum operating temperature of the NOx post-combustion control equipment and meet Rule 1109.1 concentration limits. The process heater continues to meet the 5 ppmv NOx concentration limit until October 6, 2021 at 3:00 am, where it is exceeds the concentration limit for 2 hours, before meeting 5 ppmv NOx again on October 6, 2021 at 5:00 am when fuel flow stabilizes. In this example, the process heater used 42 hours of the 48-hour startup duration limit specified in paragraph (d)(2) and is in compliance with paragraph (d)(2). The 11 hours that the unit was meeting the Rule 1109.1 concentration limit before reaching stable fuel flow is not counted towards the startup duration limit pursuant to paragraph (d)(2).

Figure 2-1 – Startup Example for Process Heater with NOx Post-combustion Control Equipment



- STARTUP means the time period that begins when a NOx emitting unit combusts fuel, after a period of zero fuel flow or zero feedstock, or when combustion/circulation air is introduced if the unit does not use fuel for combustion, and ends when the flue gas temperature reaches the minimum operating temperature of the NOx post-combustion control equipment and the unit reaches stable conditions, or when the time limit specified in Table 1 is reached, whichever is sooner.

  This proposed definition is from Rule 1134 and was modified to apply to all equipment types subject to PR 429.1. Staff worked with stakeholders to address concerns about when startup ends for a unit equipped with NOx post-combustion control equipment and units without NOx post-combustion control equipment.

  Stakeholders expressed that although NOx post-combustion control equipment needs to reach the minimum operating temperature for startup, there are additional steps, such as the injection of any associated chemical reagent, before NOx and CO concentration limits can be achieved.

Stakeholders also expressed that there are unique situations, such as the startup of a hydrogen reformer furnace, where the introduction of varying quality of gas fuel from the routing of gas to the furnace burners may cause compositional fluctuations where the control of the post-combustion control equipment is not stable. Therefore, startup is not considered to be complete until a unit reaches the minimum operating temperature of the NOx post-combustion control equipment and the unit reaches stable conditions, or the duration limit specified in Table 1, whichever is sooner. For units without NOx post-combustion control equipment, startup ends when the duration limit in Table 1 is achieved, notwithstanding the requirements of subparagraph (d)(2)(A).

One operator expressed concern with compliance and the time allotted for an FCCU startup where only combustion/circulation air is used to move catalyst prior to the startup of the unit and there are no products of combustion being produced. In this example, if no combustion is occurring where fuel is not being injected into the regenerator to initiate or sustain the heat up of the catalyst, then the relief set by PR 429.1 is not needed for this amount of time for this activity nor is the time to be deducted from the amount of time of relief established in PR 429.1.

- TUNING means adjusting, optimizing, rebalancing, or other similar operations to a gas turbine or an associated control device or otherwise as defined in a South Coast AQMD Permit to Construct or Permit to Operate. Tuning does not include normal operations to meet load fluctuations.

  This definition is from Rule 1134 and modified to include South Coast AQMD Permits to Construct.

- UNIT means equipment that is subject to Rule 1109.1 which includes boilers, flares, fluid catalytic cracking units (FCCUs), gas turbines, petroleum coke calciners, process heaters, steam methane reformer heaters, sulfuric acid furnaces, sulfur recovery units/tail gas incinerators (SRU/TG incinerators), and vapor incinerators, as defined in Rule 1109.1, requiring a South Coast AQMD Permit to Operate and not required to comply with a NOx emission limit by other South Coast AQMD Regulation XI rules.

  This definition is from PR 1109.1 and modified to refer to definitions in PR 1109.1.

- WATER FREEING means the procedure of gradually heating a unit to vaporize and remove any accumulated or condensed water in the unit during startup.

  This proposed definition describes an activity that is exempt from paragraph (d)(2) of PR 429.1 in subparagraph (g)(1)(D). Staff received comments from operators, that process heaters, such as FCCU feed pre-heaters, coker heaters, and crude unit heaters and associated equipment, may contain accumulated or condensed water which needs to be gradually boiled off so that the unit may be safely started up.

Subdivision (d) – Requirements

Exemption from Rule 1109.1 Concentration~~Emission~~ Limits During Startup, Shutdown, Commissioning and Certain~~Catalyst~~ Maintenance Events

Paragraph (d)(1) specifies that NOx and CO concentration ~~emission~~ limits in Rule 1109.1 subdivision (d), paragraph (e)(1), paragraph (e)(3)~~paragraphs (d)(3), (d)(4), Table 1, Table 2, Table 3~~, an approved B-Plan, or an approved B-Cap and the applicable rolling average provisions do not apply during startup, shutdown, maintenance for units with a permit condition before [*Date of Adoption*] which allows the use of a bypass to conduct maintenance, and catalyst maintenance events. An owner or operator is not subject to the concentration~~emission~~ limits in Rule 1109.1 and applicable rolling average provisions during tuning and commissioning, provided that a South Coast AQMD Permit to Construct or Permit to Operate specifies requirements during tuning and commissioning. For units that are included in a B-Cap, emissions may be excluded from demonstrating compliance with the NOx concentration limits (e.g., the Alternative BARCT NOx Limits); however, all emissions must be included when demonstrating the facility's daily mass emissions are below the mass cap based on the 365-day rolling average.

While a Rule 1109.1 facility is still in RECLAIM, the NOx and CO concentration~~emission~~ limits and applicable rolling average provisions in Rule 1109.1 do not apply during startup, shutdown, and maintenance for units with a permit condition before [*Date of Adoption*] which allows the use of a bypass to conduct maintenance, regardless of the length of time each event takes. If a unit has a permit condition limiting the time of startup, shutdown, or maintenance for units with a permit condition before [*Date of Adoption*] which allows the use of a bypass to conduct maintenance, the unit is only exempt from the NOx and CO concentration~~emission~~ limits and applicable rolling average provisions in Rule 1109.1 for the time specified in the permit condition. While in RECLAIM, a Rule 1109.1 facility will continue to be required to reconcile emissions under the RECLAIM program during startup, shutdown, tuning, commissioning, and maintenance for units with a permit condition before [*Date of Adoption*] which allows the use of a bypass to conduct maintenance. A Rule 1109.1 facility that has not exited RECLAIM is still subject to the NOx and CO concentration~~emission~~ limits and applicable rolling average provisions in PR 1109.1 during catalyst maintenance, unless the South Coast AQMD Hearing Board provides relief pursuant to a requested petition. A Rule 1109.1 facility, while in RECLAIM and once it exits RECLAIM, is required to take permit conditions which regulate tuning or commissioning in order to be exempt from the NOx and CO concentration~~emission~~ limits and applicable rolling average provisions in Rule 1109.1 during tuning or commissioning and is only exempt for the time specified in a South Coast AQMD Permit to Construct or Permit to Operate.

PR 429.1 specifies requirements during startup, shutdown, and catalyst maintenance once a facility exits RECLAIM. Requirements during tuning, commissioning, and maintenance for units with a permit condition before [*Date of Adoption*] which allows the use of a bypass to conduct maintenance, will be addressed in South Coast AQMD permits; the unit is only exempt from the NOx and CO concentration~~emission~~ limits and applicable rolling average provisions in Rule 1109.1 for the time specified in the permit condition. Staff evaluated permits for units with a permit condition before [*Date of Adoption*] which allows the use of a bypass to conduct maintenance to ensure that the permit requirements are collectively NAAQS protective. Once a facility exits RECLAIM, the startup and shutdown allowances specified in Table 1 (Table 2-1 in Staff Report) can be excluded from the applicable rolling average provision in PR 429.1, regardless of if PR 1109.1 concentration~~emission~~ limits were being met during startup or shutdown. If the startup or shutdown exceeds the duration limits allowed pursuant to Table 1, the owner or operator is subject to the concentration~~emission~~ limitations and applicable rolling average provisions in PR 1109.1. Refractory dryout and catalyst regeneration activities do not count towards the duration limits pursuant to paragraph (g)(1) and are not subject to the NOx and CO concentration~~emission~~ limits and applicable rolling average provisions in PR 1109.1; the unit is only exempt for the time specified in a permit condition, if applicable. Paragraph (d)(1) only provides an exemption for catalyst maintenance for a maximum of 200 hours, as subparagraph (d)(7)(A) limits use of a bypass to conduct catalyst maintenance to 200 hours in a rolling three-year cycle. Similarly, paragraph (d)(1) only provides an exemption for water freeing for a maximum of 24 hours, as specified in subparagraph (g)(1)(D). A unit operating only the pilot is not subject to the NOx and CO concentration~~emission~~ limits and applicable rolling average provisions in PR 1109.1 pursuant to PR 1109.1 paragraph (o)(7).

Startup and Shutdown Duration Limits

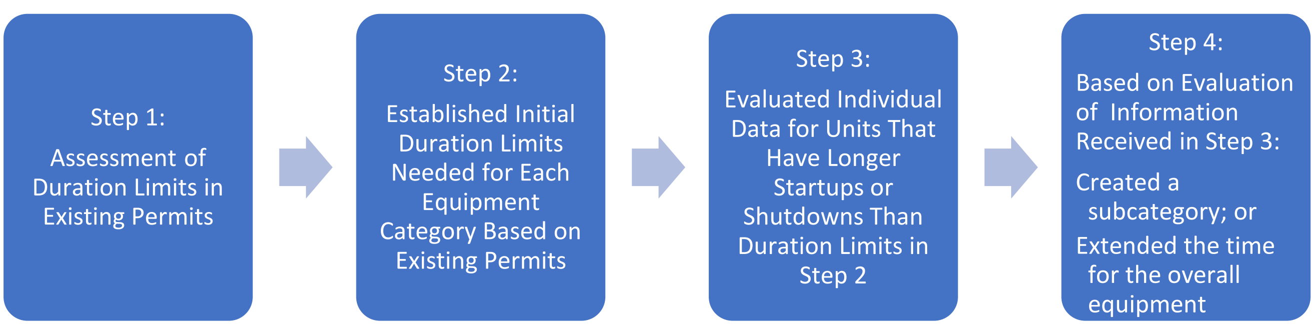
Paragraph (d)(2) includes Table 1 (Table 2-1 in Staff Report), which contains the startup and shutdown duration limits for units at former RECLAIM facilities and new facilities. Startup and shutdown duration limits only apply when a unit exceeds the applicable NOx or CO concentration limits in PR 1109.1. During the startup or shutdown of a unit, exhaust emission concentrations may fluctuate due to the nature of startups and shutdowns. Therefore, the time counted towards the startup and shutdown duration limits in PR 429.1 may be non-continuous. A unit may meet the applicable NOx and CO concentration~~emission~~ limits in PR 1109.1 temporarily during a startup or shutdown but then experience swings where the applicable concentration~~emission~~ limits are not met due to instability. The time counted towards Table 1 duration limits does not start anew if PR 1109.1 concentration~~emission~~ limits are temporarily met during the startup or shutdown, but then fluctuations result in an emission increase which exceeds applicable PR 1109.1 concentration~~emission~~ limits. However, in a situation where the owner or operator of a unit has initiated a startup of a unit but then had to shutdown the unit and will startup the unit again, then the Table 1 duration limits would apply anew. A unit with permit conditions which specifies more stringent startup or shutdown duration limits than PR 429.1 will continue to be restricted by its existing permit conditions. The duration limits in Table 1 specify the hour limitation for each individual startup or shutdown; it is not the combined time allowance for startup and shutdown. For example, a flare has 2 hours to startup and 2 hours to shutdown. PR 429.1 provides limited relief from the concentration~~emission~~ limits assigned per Rule 1109.1 for startup, shutdown, and certain defined activities. If there are periods of time during startup and shutdown ~~these activities~~ where emissions comply with the limits established in Rule 1109.1, then the limited relief is not needed for that amount of time in compliance nor is the compliant time to be deducted from the amount of time of relief established in PR 429.1.

TABLE 2-1
STARTUP AND SHUTDOWN DURATION LIMITS

Unit Type	Time Allowance (Hours)
Boilers and Gas Turbines without NOx Post-Combustion Control Equipment, Flares, Vapor Incinerators without NOx Post-Combustion Control Equipment or Castable Refractory	2
Gas Turbines with NOx Post-Combustion Control Equipment	4
Vapor Incinerators with NOx Post-Combustion Control Equipment, Vapor Incinerators with Castable Refractory	20
Process Heaters without NOx Post-Combustion Control Equipment	24
Boilers and Process Heaters with NOx Post-Combustion Control Equipment, Steam Methane Reformer Heaters, Sulfuric Acid Furnaces	48
Steam Methane Reformers with Gas Turbine	60
FCCU Feed Pre-Heater	90
FCCUs, Petroleum Coke Calciners, SRU/TG Incinerators	120

Startup and shutdown duration limits were established through an assessment which considered duration limits established in permits, the general startup and shutdown time periods necessary for each equipment category, and individual startup and shutdown data for outliers (Figure 2-2). Staff reviewed existing permits to establish a baseline for the general number of hours necessary for startup and shutdown in each equipment category. Permit conditions are tailored for specific equipment but can be reviewed in aggregate to assess the range of duration limits for a category of equipment. An inclusive duration limit was selected to be applicable to a wide range of equipment. However, where there were clear outliers, special provisions were included rather than establish excessive duration limits.

Figure 2-2 – Duration Limit Assessment



Best Management Practices

Best management practices are contained in subparagraph (d)(2)(A). If a unit reaches stable conditions and reaches the minimum operating temperature of the NOx post-combustion control equipment, if applicable, before reaching the duration limit specified in Table 1, the startup period is considered to be over, and the unit is required to meet applicable NOx and CO concentration~~emission~~ limits in PR 1109.1. Stable conditions and minimum operating temperature are defined in PR 429.1. Subparagraph (d)(2)(A) will further limit excess emissions from startup events.

Limit to the Number of Scheduled Startups

Paragraph (d)(3) limits the number of scheduled startups. Limitations to the number of scheduled startups is an existing requirement in Rule 429 and is carried forward into PR 429.1. Furthermore, limiting the frequency of scheduled startups provides further bounds to the startup and shutdown provisions. Unscheduled startups are not limited by PR 429.1 because they may be driven by operational demand, emergencies, or maintenance needs. The number of scheduled startups allowed for each unit per calendar year is specified in Table 2 (Table 2-2 in Staff Report).

TABLE 2-2
MAXIMUM NUMBER OF SCHEDULED STARTUPS

Unit Type	Maximum Number of Scheduled Startups per Calendar Year
Cogeneration Gas Turbines	10
Process Heaters on Delayed Coking Units	5
All Other Units	2

General Duty Requirements

Paragraph (d)(4) was modified from an existing Rule 429 provision and requires that an owner or operator of a unit at a former RECLAIM facility or a new facility that exceeds applicable PR 1109.1 NOx and CO concentration~~emission~~ limits during startup, shutdown, maintenance for units with a South Coast AQMD Permit to Operate condition before [*Date of Adoption*] which allows the use of a bypass to conduct maintenance, catalyst maintenance, tuning, and commissioning to take all reasonable and prudent steps to minimize emissions to meet applicable concentration~~emission~~ limits. Reasonable and prudent steps to minimize emissions include, but are not limited to, equipment repairs and adjusting the temperatures of post-combustion controls.

Requirements for Units with NOx Post-Combustion Control Equipment

Paragraph (d)(5) requires each unit equipped with NOx post-combustion control equipment to install and maintain a temperature measuring device that is calibrated annually at the inlet of the NOx post-combustion control equipment. Temperature measuring devices include thermocouples and temperature gauges. Most existing units with NOx post-combustion control equipment are already equipped with temperature measuring devices. It is standard practice to include a temperature measuring device requirement for units with NOx post-combustion control equipment in South Coast AQMD permits, and any future units would be expected to install and maintain a temperature measuring device through the permitting process. A temperature measuring device is necessary to determine the temperature of the gas stream entering the NOx post-combustion control equipment and when the catalyst in the NOx post-combustion control equipment will effectively control NOx emissions.

NOx Post-Combustion Control Equipment Operating Temperature

Paragraph (d)(6) requires the operation of NOx post-combustion control equipment during startup and shutdown events, including the injection of any associated chemical reagent into the exhaust stream to control NOx, if the temperature of the gas to the inlet of the emission control system is greater than or equal to the minimum operating temperature and the temperature is stable. Minimum operating temperature is defined in PR 429.1. ~~A unit with a permit condition specifying a lower temperature to operate its NOx post-combustion control equipment than PR 429.1 will continue to be restricted by its existing permit condition.~~

Catalyst Maintenance Provision

Paragraph (d)(7) specifies requirements for an owner or operator of a unit at a former RECLAIM facility that elects to use a bypass to conduct catalyst maintenance. Only units which have a bypass stack or duct that exists prior to *[Date of Adoption]* may elect to use a bypass to conduct catalyst maintenance. Catalyst used in NOx post-combustion control equipment at petroleum refineries and at facilities with related operations to petroleum refineries typically needs to be replaced every 3-6 years, which is shorter than the turnaround schedules for some units. The process of starting up and shutting down units to conduct maintenance on NOx post-combustion control equipment can result in more emissions than if the NOx post-combustion control equipment were bypassed temporarily and the unit was kept in operation. This provision is only for units that are equipped with a stack or ducting that allows for bypassing the unit's NOx post-combustion control equipment by [*Date of Adoption*]. If a permit contains more stringent requirements than PR 429.1, the more stringent permit requirements will continue to be applicable.

Subparagraph (d)(7)(A) precludes the use of a bypass to conduct catalyst maintenance for units that are scheduled to operate continuously for less than five years between planned maintenance shutdowns of the unit. Subparagraph (d)(7)(A) is included to limit the catalyst maintenance provision to units that have long turnaround schedules. Turnarounds typically occur every 3-5 years for refinery equipment, but some units have turnaround schedules that are 9 years or longer.

Subparagraph (d)(7)(B) limits the use of a bypass to condition, repair, or replace the catalyst in the NOx post-combustion control equipment to 200 hours in a rolling three-year cycle. Therefore, catalyst used in a NOx combustion control equipment could be conditioned, repaired, or replaced every three years under subparagraph (d)(7)(B). Three years is a conservative estimate of catalyst life; catalysts typically need to be replaced every 3-6 years.

Subparagraph (d)(7)(C) specifies that the process unit must be operated at 50% of the feed rate~~rated heat input capacity~~ of the process unit or less when the NOx post-combustion control equipment is bypassed. Feed rate is defined in PR 429.1.~~PR 429.1 refers to the definition of rated heat input capacity in Rule 1109.1.~~ Staff established the percentage of feed rate~~rated heat input capacity~~ based on information provided by stakeholders of minimum safe operating rates. Subparagraph (d)(7)(C) is included to reduce emissions by lowering the rate that a process unit is operating at when using a bypass to conduct catalyst maintenance.

Subparagraph (d)(7)(D) provides notification requirements during catalyst maintenance. Notifications are required to be made by calling to 1-800-CUT-SMOG at least 24 hours before bypassing the NOx post-combustion control equipment and ~~to~~ include the date, ~~and~~ estimated time, and estimated duration that the NOx post-combustion control equipment will be bypassed. Advanced notification of these events is considered important because it gives the South Coast AQMD time to allocate resources if necessary to monitor the catalyst maintenance activity and information to respond to inquiries from the community should they arise.

Subparagraph (d)(7)(E) contains a requirement to continuously monitor NOx and CO emissions during catalyst maintenance. PR 429.1 only requires NOx and CO emissions to be continuously monitored when the owner or operator elects to bypass the NOx post-combustion control equipment to conduct catalyst maintenance. The continuous monitoring is required to be conducted with a certified Continuous Emissions Monitoring System (CEMS) pursuant to Rule 218.2 – Continuous Emission Monitoring System: General Provisions and Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications or by a contractor approved under the South Coast AQMD Laboratory Approval Program (LAP) if emissions cannot be monitored by a certified CEMS.

Paragraph (d)(7) is intended only for activities involved in catalyst maintenance, as described in in subdivision (c). This provision is not intended to provide relief for malfunctions or breakdowns of ancillary equipment used in the operation of NOx post-combustion control equipment. In situations not related to the conditioning, repairing, or replacement of catalyst in NOx post-combustion control equipment, but related to breakdowns of ancillary equipment used in the operation of the NOx post-combustion equipment, paragraph (d)(7) does not apply. For example, if a situation arose where the ammonia injection system associated with the NOx post-combustion control equipment were to stop working and require repair, this situation is not covered under this provision. Rather, South Coast AQMD Rule 430 – Breakdown Provisions (Rule 430), may provide relief from rules or permit conditions during breakdowns as long as specific conditions and requirements are met or the owner or operator may seek additional relief through the Hearing Board process.

Subdivision (e) – Notification

Paragraph (e)(1) provides notification requirements for scheduled startups. Notifications are required to be made by calling 1-800-CUT-SMOGat least 24 hours before the scheduled startup and include the date and time of the scheduled startup. Advanced notification of these events is considered important because it gives the South Coast AQMD time to allocate resources if necessary to monitor the startup and information to respond to inquiries from the community should they arise.

Subdivision (f) – Recordkeeping

Records assist in verifying compliance with Rule 429.1. Paragraph (f)(1) provides recordkeeping requirements for owners and operators of units at a former RECLAIM facility or a new facility. Records are required to be maintained on-site for 5 years and made available to the South Coast AQMD upon request. The provision in subparagraph (f)(1)(A) requires the operating log to contain the date, time, duration, and reason for each startup, shutdown, refractory dryout, catalyst maintenance, catalyst regeneration activity, tuning, commissioning, and water freeing event. An operating log may also contain but is not limited to operator signed-off procedures and graphical trends showing key variables of the unit such as temperatures and flow rates. Staff notes that it is the responsibility of the operator to demonstrate to the Executive Officer and their representative that compliance with duration limits or with specified exempt activities under PR 429.1 is met. For startups, the reason provided in the operating log must specify if the startup was scheduled. Subparagraphs (f)(1)(B) through (f)(1)(D) requires a list of scheduled startups, a list of planned maintenance shutdowns for the next 5 years for each unit equipped with a bypass stack or duct that exists prior to [*Date of Adoption*], and NOx and CO emissions data collected pursuant to subparagraph (d)(7)(E).

Paragraph (f)(2) requires an owner or operator of a unit at a former RECLAIM facility or a new facility equipped with NOx post-combustion control equipment to maintain documentation from the manufacturer of the minimum operating temperature of the NOx post-combustion control equipment, unless the South Coast AQMD Permit to Construct or Permit to Operate specifies the required minimum operating temperature of the NOx post-combustion control equipment. Records are required to be on-site and made available to the South Coast AQMD upon request for compliance verification.

Subdivision (g) – Exemptions

Paragraph (g)(1) exempts units from the startup and shutdown duration limits contained in paragraph (d)(2) during refractory dryouts, catalyst regeneration activities, and commissioning, and a maximum of 24 hours for water freeing a unit. Temperatures are not high enough for NOx post-combustion control equipment to be effective during refractory dryouts, catalyst regeneration activities, and water freeing. Furthermore, refractory dryouts and catalyst regeneration activities are infrequent processes during which the expected mass emissions of NOx are low. The expected mass emissions during water freeing are also low and stakeholders expressed that there are significant safety issues associated with starting up too quickly without properly removing condensed water from the unit. The safety issues include concern of the potential rapid vaporization of liquid water in parts of the unit where such a large volume expansion may damage equipment. The exemption from startup and shutdown duration limits during water freeing is limited to 24 hours. The initial commissioning of a unit or the initial commissioning of NOx post-combustion control equipment only occurs once, and specific conditions are established by South Coast AQMD's Engineering and Permitting Division for this time period. Electrical testing for cogeneration turbines is required by the North American Electric Reliability Corporation, and specific conditions will be required by South Coast AQMD's Engineering and Permitting Division.

Paragraph (g)(2) exempts units equipped with a NOx post-combustion control equipment from the catalyst maintenance requirements in paragraph (d)(7) if the unit has a permit condition before

[*Date of Adoption*] that allows the use of a bypass for maintenance. A unit that qualifies for the exemption in paragraph (g)(2) will continue to be restricted by its current permit conditions.

Paragraph (g)(3) exempts units burning fuel exclusively in a pilot light from the startup and shutdown duration limits contained in paragraph (d)(2) and recordkeeping requirements specified in paragraph (f)(1). Fuel burned in a pilot light contributes relatively minimal emissions and is not the primary NOx emission source in combustion equipment.

CHAPTER 3: IMPACT ASSESSMENTS

INTRODUCTION

Impact assessments were conducted during PR 429.1 rule development to assess the environmental and socioeconomic implications of PR 429.1. California Health & Safety Code (H&SC) requirements for cost-effectiveness analysis and incremental cost-effectiveness analysis were evaluated during rule development of PR 429.1. Staff prepared an assessment of emission reductions, a socioeconomic assessment, and a California Environmental Quality Act (CEQA) analysis. Draft findings and comparative analyses were prepared pursuant to California Health and Safety Code Section (H&SC) 40727 and H&SC 40727.2, respectively.

COSTS

The provisions in PR 429.1 are not expected to impose any additional costs.

EMISSION REDUCTIONS

There will not be additional emission reductions from combustion equipment subject to PR 429.1; all emission reductions for these units are a result of PR 1109.1.

COST-EFFECTIVENESS

The H&SC Section 40920.6 requires a cost-effectiveness analysis when establishing BARCT requirements. The proposed rule does not include new BARCT requirements. Therefore, this provision does not apply to the proposed rule.

INCREMENTAL COST-EFFECTIVENESS

H&SC Section 40920.6 requires an incremental cost-effectiveness analysis for BARCT rules or emission reduction strategies when there is more than one control option which would achieve the emission reduction objective of the proposed amendments, relative to ozone, CO, SOx, NOx, and their precursors. The proposed rule does not include new BARCT requirements. Therefore, this provision does not apply to the proposed rule.

SOCIOECONOMIC ASSESSMENT

The proposed rule 429.1 does not impose any additional costs to the affected facilities and does not result in any adverse socioeconomic impacts.

CALIFORNIA ENVIRONMENTAL QUALITY ACT ANALYSIS

Pursuant to the California Environmental Quality Act (CEQA) and South Coast AQMD's Certified Regulatory Program (Public Resources Code Section 21080.5 and CEQA Guidelines Section 15251(l); codified in South Coast AQMD Rule 110), the South Coast AQMD is lead agency for the proposed project, which is comprised of Proposed Rules 1109.1 and 429.1, Proposed Amended Rules 1304 and 2005, and Proposed Rescinded Rule 1109. CEQA Guidelines Section 15187 requires an environmental analysis to be performed when a public agency proposes to adopt a new rule or regulation requiring the installation of air pollution control equipment or establishing a performance standard, which is the case with the proposed project. The South Coast AQMD has prepared a Subsequent Environmental Assessment (SEA) for the proposed project, which is a substitute CEQA document pursuant to CEQA Guidelines Section 15252, prepared in lieu of a Subsequent Environmental Impact Report. The SEA contains the environmental analysis required by CEQA Guidelines Section 15187 and tiers off of the December 2015 Final Program Environmental Assessment (PEA) for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM) (referred to as NOx RECLAIM) and the March 2017 Final Program Environmental Impact Report (EIR) for the 2016 Air Quality Management Plan as allowed by CEQA Guidelines Sections 15152, 15162, 15168 and 15385. The Draft SEA was released for a 46-day public review and comment period to provide public agencies and the public an opportunity to obtain, review, and comment on the environmental analysis. ~~Comments made relative to the analysis in the Draft SEA and responses to the comments will be included in the Final SEA.~~ The South Coast AQMD received six comment letters relative to the analysis in the Draft SEA and responses to the comments have been included in the Final SEA.

DRAFT FINDINGS UNDER CALIFORNIA HEALTH AND SAFETY CODE SECTION 40727

Requirements to Make Findings

H&SC 40727 requires that prior to adopting, amending or repealing a rule or regulation, the South Coast AQMD Governing Board shall make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the public hearing and in the staff report. The draft findings are as follows:

Necessity

PR 429.1 is needed to establish limits on duration and frequency of startup and shutdown events for units at petroleum refineries and facilities with related operations to petroleum refineries when units exceed the applicable NOx or CO limits in Rule 1109.1.

Authority

The South Coast AQMD obtains its authority to adopt, amend, or repeal rules and regulations pursuant to H&SC Sections 39002, 39616, 40000, 40001, 40440, 40702, 40725 through 40728, 40920.6, and 41508, as well as the federal Clean Air Act.

Clarity

PR 429.1 is written or displayed so that its meaning can be easily understood by the persons directly affected by them.

Consistency

PR 429.1 is in harmony with and not in conflict with or contradictory to, existing statutes, court decisions or state or federal regulations.

Non-Duplication

PR 429.1 will not impose the same requirements as any existing state or federal regulations. The proposed rule is necessary and proper to execute the powers and duties granted to, and imposed upon, the South Coast AQMD.

Reference

In adopting this rule, the following statutes which the South Coast AQMD hereby implements, interprets or makes specific are referenced: H&SC Sections 39002, 40001, 40702, 40440(a), and 40725 through 40728.5, and the federal Clean Air Act.

COMPARATIVE ANALYSIS

Under H&SC Section 40727.2, the South Coast AQMD is required to perform a comparative written analysis when adopting, amending, or repealing a rule or regulation. The comparative analysis is relative to existing federal air pollution control requirements, existing or proposed South Coast AQMD rules and regulations, and all air pollution control requirements and guidelines which are applicable to the same equipment or source type. A comparative analysis is presented below in Table 3-1.

TABLE 3-1
PR 429.1 COMPARATIVE ANALYSIS

Rule Element	PR 429.1	PR 1109.1	RECLAIM	CFR Title 40, Vol. 7, Part 60, Subpart J	CFR Title 40, Vol. 7, Part 60, Subpart Ja	CFR, Title 40, Vol. 7, Part 60, Subpart GG	CFR, Title 40, Vol. 8, Part 60, Subpart KKKK	CFR, Title 40, Vol. 7, Part 60, Subpart Db	CFR, Title 40, Vol. 7, Part 60, Subpart Dc	CFR, Title 40, Vol. 7, Part 60, Subpart Cd	CFR, Title 40, Vol. 7, Part 60, Subpart H
Applicability	Units at petroleum refineries and facilities with related operations to petroleum refineries	Units at petroleum refineries and facilities with related operations to petroleum refineries	Facilities up until January 5, 2018, unless otherwise exempted, if emission fee data for 1990 or any subsequent year filed pursuant to Rule 301, shows 4 or more tons per year of NOx or SOx emissions	Fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants with a design capacity for sulfur feed of 20 long tons per day or less.	Fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares and sulfur recovery plants.	Gas turbines with heat input of ≥ 10 MMBtu/hr that commenced construction, modification or re-construction on on or before 2/18/2005	Gas turbines with heat input of ≥ 10 MMBtu/hr that commenced construction, modification or re-construction after 2/18/2005	Steam generating units that commenced construction, modification, or re-construction after 6/19/1984 and that has a heat input capacity of >29 MW (100 MMBtu/hr)	Steam generating units that commenced construction, modification, or re-construction after 6/9/1989 and that has a heat input capacity of 29 MW or less, but ≥ 2.9 MW (10 MMBtu/Hr)	Sulfuric acid production units	Sulfuric acid production units that commenced construction or modification after 8/17/1971
Requirements	Startup and shutdown duration limits: • Boilers and Gas Turbines without NOx Post-Combustion Control Equipment, Flares, Vapor Incinerators without NOx Post-Combustion Control	Emission limits: • Boilers <40 MMBtu/hr: 5 ppmv NOx and 400 ppmv CO @3% O_2, 24 hour rolling average • Boilers ≥ 40 MMBtu/hr:5 ppmv NOx and 400 ppmv CO @3% O_2, 24 hour	• Comply with all applicable rules and permit conditions as specified in the Facility Permit • Prohibition of emissions in excess of annual allocation • Modeling if actual NOx or	FCCU catalyst regenerators: • Particulate matter (PM) limit: 1.0 kg/Mg of coke burn-off in the catalyst regenerator	All emission limits are dry @ 0% excess air: ○ FCCU & FCU: • PM: 1 g/kg coke burn-off for modified or reconstructed FCCU & FCU; 0.5 g/kg coke burn-off for newly constructed FCCU • NOx: 80 ppmv, 7-day rolling average • SO_2: 50 ppmv, 7-day rolling average; 25 ppmv, 365-day rolling average	NOx limit @ 15% O_2, where Y = Manufacture's rated heat input and F = NOx emission allowance for fuel-bound nitrogen:	NOx limit @ 15% O_2: • ≤ 50 MMBtu/hr – 42 ppm new, firing natural gas, electric generating • ≤ 50 MMBtu – 100 ppm new, firing natural gas, mechanical drive	SO_2 limits (30-day rolling average, except as provided in paragraph (f), apply at all times including SSM, except as provided in paragraph (i)* of this section and §60.45b(a)): • Affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal or oil: 87 ng/J or 10% of the potential SO_2 emission rate and $E_s = \frac{(K_a H_a + K_b H_b)}{(H_a + H_b)}$	SO_2 limits (30-day rolling average, apply at all times including startup, shutdown, and malfunction): • Affected facility that combusts only coal or	H_2SO_4 mist limit: 0.25 grams of H_2SO_4 mist (as measured by EPA Reference Method 8 of appendix	SO_2 limit: 2 kg per metric ton of acid produced, the production being expressed as 100% H_2SO_4

Rule Element	PR 429.1	PR 1109.1	RECLAIM	CFR Title 40, Vol. 7, Part 60, Subpart J	CFR Title 40, Vol. 7, Part 60, Subpart Ja	CFR, Title 40, Vol. 7, Part 60, Subpart GG	CFR, Title 40, Vol. 8, Part 60, Subpart KKKK	CFR, Title 40, Vol. 7, Part 60, Subpart Db	CFR, Title 40, Vol. 7, Part 60, Subpart Dc	CFR, Title 40, Vol. 7, Part 60, Subpart Cd	CFR, Title 40, Vol. 7, Part 60, Subpart H
	Equipment or Castable Refractory – 2 hours • Gas Turbines with NOx Post-Combustion Control Equipment – 4 hours • Vapor Incinerators with NOx Post-Combustion Control Equipment, Vapor Incinerators with Castable Refractory – 20 hours • Process Heaters without NOx Post-Combustion Control Equipment – 24 hours • Boilers and Process Heaters with NOx Post-Combustion Control Equipment, Steam Methane Reformer Heaters, Sulfuric Acid Furnace – 48 hours • Steam Methane Reformer with Gas Turbine – 60 hours	rolling average • Flares: 20 ppmv NOx and 400 ppmv CO @3% O_2, 2 hour rolling average • FCCU (@ 3% O_2): 2 ppmv NOx and 500 ppmv CO (365 day rolling average); and 5 ppmv NOx and 500 ppmv CO (7 day rolling average) • Gas Turbines (@15% O_2, 24 hour rolling average): 2 ppmv NOx for natural gas units, 3 ppmv NOx for gaseous fuel other than natural gas; and 130 ppmv CO • Petroleum Coke Calciner (@ 3% O_2): 5 ppmv NOx (365 day rolling average); and 10 ppmv NOx (7 day rolling average); and 2000 ppmv CO	SOx emissions exceed its initial allocation by ≥ 40 tons per year • Effective 11/15/1998 each new, modified, and existing electric utility and industrial and commercial boiler which emits > 25 tons per year of NOx shall burn as its primary fuel natural gas, methanol, or ethanol (or a comparably low polluting fuel); or use advanced control technology Emission Limits: • FCCU – 25 ppm SOx, dry @ 0% oxygen on a 365- day rolling average Emission Factors NOx: • Refinery boiler >40	• Opacity limit: >30% except for one six-minute averaging opacity reading in any one hour period • CO limit: 500 ppmv (dry basis) • Comply with one of the following conditions (7-day rolling average): with an add-on control device reduce SO_2 emissions by 90% or maintain at ≤ 50 ppmv, whichever is less stringent; without the use of a control device, maintain SO_2 emissions at ≤ 9.8	• CO: 500 ppmv, hourly average ○ Sulfur recovery plant (emission limits do not apply during maintenance of the sulfur pit, not to exceed 240 hours/year): • SO_2 limit for > 20 LTD with oxidation or reduction control system followed by incineration: $E_{LS}= k_1$ x (-0.038 x $(\%O_2)^2$ + 11.53 x $\%O_2$ + 25.6); 250 ppmv for Claus units that use only ambient air or elect not to monitor O_2 or for non-Claus • > 20 LTD with reduction control system not followed by incineration: SO_2 E_{LS}= k_1 x (-0.038 x $(\%O_2)^2$ + 11.53 x $\%O_2$ + 25.6); 300 ppmv SO_2 for Claus units that use only ambient air or non-Claus; 10 ppmv H_2S • SO_2 limit ≤ 20 LTD with oxidation or reduction control system followed by incineration: $E_{SS}= k_1$ x (-0.38 x $(\%O_2)^2$ + 115.3 x $\%O_2$ + 256); 2500 ppmv for Claus units that use only ambient air or elect not to monitor O_2 or for non-Claus • ≤ 20 LTD with reduction control system not followed by incineration: SO_2 E_{SS}= k_1 x (-0.38 x $(\%O_2)^2$ + 115.3 x $\%O_2$ + 256);	• 0.0075* (14.4/Y) +F • 0.0150* (14.4/Y) +F SO_2 limit @15% O2: • 0.015% by volume	• > 50 MMBtu/hr and ≤ 850 MMBtu/hr – 25 ppm new, firing natural gas • >850 MMBtu/hr – 15 ppm new, modified, or reconstructed, firing natural gas • ≤ 50 MMBtu/hr – 96 ppm new, firing fuels other than natural gas, electric generating • ≤ 50 MMBtu/hr – 150 ppm new, firing fuels other than natural gas, mechanical drive • > 50 MMBtu/hr and ≤ 850 MMBtu/hr – 74 ppm new, firing fuels other than natural gas • >850 MMBtu/hr	• Affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal refuse alone in a fluidized bed combustion steam generating unit: 87 ng/J or 20% of the potential SO_2 emission rate and 520 ng/J heat input • Affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology to control SO_2: 50% of the potential SO_2 emission rate and $E_s = \frac{(K_c H_c + K_d H_d)}{(H_c + H_d)}$ • Affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that: have an annual capacity factor for coal and oil of ≤30% and a federally enforceable permit limiting operation; is located in a noncontinental area; combusts coal and oil, alone or in combination with a duct burner as part of a combined cycle system where ≤30% of the heat entering the steam generating unit is from combustion of coal and oil in the duct burner and ≥70% of the heat entering the steam generating unit is from the exhaust gases entering the duct burner; or burns coke oven gas alone or in combination with natural gas or very low sulfur distillate oil: 520 ng/J if the facility combusts coal or 215	coal with coal refuse: 87 ng/J (0.20 lb/MMBTU) heat input or 10% of the potential SO_2 emission rate and 520 ng/J (1.2 lb/MMBtu) heat input • Affected facility that combusts coal or coal refuse with other fuels: 87 ng/J (0.20 lb/MMBTU) heat input or 10% of the potential SO_2 emission rate and $E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$ • Affected facility that combusts only coal refuse alone in a fluidized bed combustion steam generating unit: 87 ng/J (0.20 lb/MMBTU) heat input or 20% of the potential SO_2 emission rate and 520 ng/J (1.2	A of this part) per kilogram of H_2SO_4 produced, the production being expressed as 100% H_2SO_4	Acid mist standards: • H_2SO_4 limit of 0.075 kg per metric ton of acid produced, the production being expressed as 100% H_2SO_4 • Opacity limit of 10%

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	• FCCU Feed Pre-Heater – 90 hours • FCCU, Petroleum Coke Calciner, SRU/TG Incinerators – 120 hours Scheduled startup limits per calendar year for each unit: • Cogeneration gas turbine– 10 • Process heaters on delayed coking units– 5 • All other units – 2 Work practice requirements: • Take all reasonable and prudent steps to minimize emissions during startup and shutdown, maintenance for units with a South Coast AQMD Permit to Operate condition before [Date of Adoption] which allows the use of a bypass to conduct	• Process Heaters <40 MMBtu/hr: 9 ppmv NOx and 400 ppmv CO @3% O_2, 24 hour rolling average • Process Heaters ≥ 40MMBtu/hr: 5 ppmv NOx and 400 ppmv CO @3% O_2, 24 hour rolling average • SRU/TG Incinerators: 30 ppmv NOx and 400 ppmv CO @3% O_2, 24 hour rolling average • SMR Heaters: :5 ppmv NOx and 400 ppmv CO @3% O_2, 24 hour rolling average • SMR Heater with Gas Turbine: 5 ppmv NOx and 130 ppmv CO @15% O_2, 24 hour rolling average • Sulfuric Acid Furnace:	MMBtu/hr – 2 ppm • FCCU – 2 ppm • Gas turbines – 2 ppm • Calciner – 10 ppm • SRU/TG unit – 95% reduction, 2 ppm Emission Standards SOx: • Calciner – 10 ppmv • FCCU – 5 ppmv • Refinery boiler/heater – 40 ppmv • SRU/TG unit – 5 ppmv • Sulfuric acid manufacturing – 10 ppmv	kg/Mg coke burn-off; or process in the FCCU fresh feed that has a sulfur content ≤ 0.30% by weight All units: • H_2S limit:230 mg/dscm Claus sulfur recovery plant: • For an oxidation control system or a reduction control system followed by incineration, SO_2 limit: 250 ppm by volume (dry basis at 0% excess air) • For a reduction control system not followed	3000 ppmv SO_2 for Claus units that use only ambient air or for non-Claus; 100 ppmv H_2S ○ Fuel gas combustion devices: • 20 ppmv SO_2 (3-hour rolling average) and 8 ppmv SO_2 (365 day rolling average) or 162 ppmv H_2S (3 hour rolling average) and 60 ppmv H_2S (365 day rolling average) • Process heaters > 40 MMBtu/hr (30 day rolling average): 40 ppmv or 0.040 lb/MMBtu for natural draft process heaters; 60 ppmv or 0.060 lb/MMBtu for forced draft process heaters; 150 ppmv or Equation 3 for co-fired natural draft process heaters; 150 ppmv or Equation 4 for co-fired forced draft process heaters ○ Flare: 162 ppmv H_2S, 3 hour rolling average Flare management plan, root cause and corrective analysis, implement corrective actions, depressure delayed coking units to ≤ 5 psig prior to discharging exhaust		– 42 ppm new, modified, or reconstructed, firing fuels other than natural gas • ≤ 50 MMBtu/hr – 150 ppm modified or reconstructed • > 50 MMBtu/hr and ≤ 850 MMBtu/hr – 42 ppm modified or reconstructed, firing natural gas • > 50 MMBtu/hr and ≤ 850 MMBtu/hr – 96 ppm modified or reconstructed, firing fuels other than natural gas SO_2 limit: • 110 ng/J • 65 ng/J for turbines burning at least 50% biogas in a calendar month	ng/J if the facility combusts oil other than very low sulfur oil • Affected facility that commenced construction, reconstruction, or modification after February 28, 2005 and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels: 87 ng/J or 8% of the potential SO2 emissions and 520 ng/J * An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the SO_2 control system is not being operated because of malfunction or maintenance of the SO_2 control system Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil are allowed to exceed the limit 30 operating days per calendar year for SO_2 control system maintenance. PM and Opacity Limits (apply at all times except startup, shutdown, or malfunction, 24 hour average): • Affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and that combusts coal or combusts mixtures of coal with other fuels: 22 ng/J (only coal or if the affected facility combusts coal and other fuels	lb/MMBtu) heat input • Affected facility that combusts only coal and that uses an emerging technology for the control of SO_2 emissions: 50% of the potential SO_2 emission rate and 260 ng/J (0.60 lb/MMBtu) heat input • Affected facility that combusts coal with other fuels and that uses an emerging technology for the control of SO_2 emissions: 50% of the potential SO_2 emission rate and $E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$ • Affected facility that combusts coal alone or in combination with another fuel that has		

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	maintenance, catalyst maintenance, tuning, and commissioning • Operate NOx post-combustion control equipment if the temperature to the gas at the inlet of the NOx post-combustion control equipment is ≥ the minimum operating temperature Install and maintain a calibrated temperature measuring device on all units with NOx post-combustion control equipment Units with a bypass stack or duct by [Date of Adoption] that elects to use a bypass to conduct catalyst maintenance: shall not use a bypass if the unit is scheduled to	30 ppmv NOx and 400 ppmv CO @3% O_2, 365 day rolling average • Vapor Incinerators: 30 ppmv NOx and 400 ppmv CO @3% O_2, 24 hour rolling average		by incineration: limits of 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis at 0% excess air)			Operate and maintain stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.	and has an annual capacity factor for the other fuels of ≤10%), 43 ng/J (affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels > 10 percent% and is subject to a federally enforceable requirement), 86 ng/J (combusts coal or other fuels and has an annual capacity factor for coal or coal and other fuels of ≤30%, has a maximum heat input of ≤73 MW, has a federally enforceable limit ,construction of the affected facility commenced after June 19, 1984, and before November 25, 1986) • Affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts oil (or mixture of oil with other fuels) and uses a SO2 control technology: 43 ng/J • Affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts wood, or wood with other fuels, except coal: 43 ng/J (annual capacity factor >30% for wood) or 86 ng/J (annual capacity factor ≤30% for wood and subject to a federally enforceable annual capacity limit and a heat input capacity of ≤73 MW) • Affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels: 43 ng/J (only	a heat input capacity of ≤ 22 MW, is subject to a federally enforceable requirement of an annual capacity factor for coal of ≤55%, located in a noncontinental area, or combusts coal in a duct burner as part of a combined cycle system where ≤30% of the heat entering the steam generating unit is from combustion of coal in the duct burner and ≥70% of the heat entering the steam generating unit is from exhaust gases entering the duct burner: $E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$ PM and Opacity Limits		

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	operate for <5 years between planned maintenance shutdowns, shall not use a bypass to conduct catalyst maintenance for more than 200 hours in a rolling 3 year cycle, operate the process unit at 50% of the feed rate~~rated heat input capacity~~ or less; notification, continuous monitoring							municipal-type solid waste or combusts municipal type solid waste and other fuels and has an annual capacity factor for the other fuels of ≤10%), 86 ng/J (has an annual capacity factor for municipal-type solid waste and other fuels of ≤ 30%, a maximum heat input of ≤ 73 MW, a federally enforceable annual capacity limit, and construction of the affected facility commenced after June 19, 1984, but on or before November 25, 1986) • Affected facility that combusts coal, oil, wood, or mixture of these fuels with other fuels: 20% opacity (6 minute average) • Affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5), and (h)(6): 13 ng/J NOx limits (apply at all times including startup, shutdown, and malfunction, 30-day rolling average, except as provided in paragraph (j)): • Natural gas and distillate oil, except duct burners in combined cycle systems: 43 ng/J (low heat release), 86 ng/J (high heat release) • Residual Oil: 130 ng/J (low heat release), 170 ng/J (high heat release)	(apply at all times except during startup, shutdown, and malfunction): • Affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, combusts coal or coal with other fuels, a heat input capacity ≥ 8.7 MW: 22 ng/J PM (annual capacity factor for the other fuels of 10% or less) or 43 ng/J PM (annual capacity factor for the other fuels >10%, and subject to a federally enforceable requirement) • Affected facility that commenced construction, reconstructio		

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								• Coal: 210 ng/J (mass-feed stoker), 260 ng/J (spreader stoker and fluidized bed combustion), 300 ng/J (pulverized coal), 260 ng/J (Lignite), 340 ng/J (Lignite mined in North Dakota, South Dakota or Montana and combusted in a slag tap furnace), 210 ng/J (coal-derived synthetic fuels) • Duct burner in a combined cycle system: 86 ng/J (natural gas and distillate oil), 170 ng/J (residual oil) • Simultaneous combustion of mixtures of only coal, oil, or natural gas $E_n = \frac{(EL_{go}H_{go})+(EL_{ro}H_{ro})+(EL_c H_c)}{(H_{go}+H_{ro}+H_c)}$ • Affected facility that simultaneously combusts coal or oil, natural gas (or any combination of the three), and wood, or any other fuel: Emission limit pursuant to paragraph (a) or (b) • Affected facility that simultaneously combusts natural gas and/or distillate oil with a potential SO2 emissions rate of ≤26 ng/J with wood, municipal-type solid waste, or other solid fuel, except coal: 130 ng/J • Affected facility that commenced construction after July 9, 1997: 86 ng/J (combusts coal, oil, or natural gas, or any combination of the three)	n, or modification on or before February 28, 2005, combusts wood or wood with other fuels (except coal), a heat input capacity ≥ 8.7 MW: 43 ng/J PM (annual capacity factor for wood >30%) or 130 ng/J PM (annual capacity factor for wood ≤ 30% and federally enforceable limit) • Affected facility that combusts coal, wood or oil, a heat input capacity ≥ 8.7 MW: 20% opacity (6 minute average) • Affected facility that commenced construction, reconstruction, or modification on or before		

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									February 28, 2005, combusts wood, oil, coal, or a mixture of these fuels, wood with other fuels with any other fuels, a heat input capacity ≥ 8.7 MW: 13 ng/J PM		
Monitoring	Continuous monitoring with a certified CEMS or a Laboratory Approval Program approved contractor is required if bypassing NOx post-combustion control equipment for catalyst maintenance	Continuous monitoring with a certified CEMS (as specified in Rules 218.2 and 218.3) to measure NOx and O2 for units ≥40 MMBtu/hr and sulfuric acid furnaces. Unit with CO CEMS are required to be certified and operated in compliance with Rules 218.2 and 218.3. Units without a CEMS must conduct source tests for units without ammonia emissions in	• Continuous monitoring device for each as specified in Rule 2012, Appendix A and Rule 2011, Appendix A for each major NOx or SOx source • Source testing every 6 months for major NOx sources at a Super Compliant NOx facility which is reclassified as a large NOx source • Source testing every 12 months (units with emission rates) and	• Initial performance test for all units and daily performance test for FCCU catalyst regenerators (7-day average) • Test methods: 5B, 5F, 9, 2, 3B, 11, 15, 15A,16, 6, 6C, 3, 3A,4, 8, 1, ASTM D129–64, 78, or 95, ASTM D1552–83 or 95, ASTM D2622–87, 94, or 98, or ASTM	• Initial performance test • Test methods: Method 1 of Appendix A-1 to part 60, Method 2 of appendix A-1 to part 60, Method 3, 3A, or 3B of appendix A-2 to part 60, Method 5, 5B, or 5F of appendix A-3 to part 60, Method 7, 7A, 7C,7D or 7E of appendix A-4 to part 60, Method 10, 10A, or 10B of appendix A-4 to part 60, Method 6, 6A, or 6C of appendix A-4 to part 60, Method 15 or 15A of appendix A-5 to part 60, Method 16 of appendix A-6 to part 60, Method 11, Method 18 of appendix A-6 to part 60, ASTM D1945–03, ASTM D1946–90, ASTM D6420–99, GPA 2261–00, ASTM UOP539–97, EPA Method 2, 2A, 2B, 2C or 2D of appendix A–2 to part 60, ASME	• Performance test using either: EPA Method 20; ASTM D6522-00; EPA Method 7E and either EPA Method 3 or 3A; sampling traverse points following Method 20 or Method 1, and sampled for equal time intervals • A continuous	• Initial performance test • Test methods: EPA Methods 7E and 3A, EPA Method 20, EPA Method 19 • A continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel or CEMS for stationary gas turbines using water or steam injection	• Performance tests • Test Methods: Method 19, Method 3A or 3B, Method 5, 5B, or 17, Method 5, Method 17, Method 1, Method 9, Method 7E, Method 7,7A, 7E, Method 320 • Quarterly accuracy determinations and daily calibration drift tests for CEMS • SO_2 CEMS except as provided in paragraphs (b) and (f) • Continuous opacity monitoring systems (COMS)	• Initial performance test • Test Methods for PM: Method 1, Method 3A or 3B, Method 5, 5B, or 17, Method 9 • CEMS for measuring SO_2 and either O_2 or CO2 at the outlet of the SO_2 control device (or unit if there is no control device); 1 hour average • Quarterly accuracy determinations and daily calibration drift tests • COMS	None	• Performance test • Test Methods: Method 8, Method 9, Method 3 • Continuous monitoring system for SO_2.

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		the exhaust (vapor incinerators <40 MMBtu/hr and flares: every 36 months; all other units without NOx or CO CEMS : quarterly; units with NOx CEMS and without CO CEMS: every 12 months; units without NOx CEMS and with CO CEMS: quarterly) and with ammonia emissions in the exhaust (units without NOx, CO, or ammonia CEMS: quarterly; units with NOx CEMS and without CO and ammonia CEMS: quarterly; units with NOx and CO CEMS and without ammonia CEMS: quarterly; units with	every 6 months (units with concentration limits) for major SOx sources at a Super Compliant SOx facility which is reclassified as a SOx process unit • Source testing shall comply with District Source Test Methods 1.1, 1.2, 2.1, 2.2, 2.3, 3.1, 4.1, 6.1, 7.1, 307-91, and 100.1; ASTM Methods D3588-91, D4891-89, D1945-81, D4294-90, and D2622-92; and EPA Method 19 • Source testing once every 3 years for large NOx sources • Source testing once every 5 years for NOx process units	D1266–87, 91, or 98. • Continuous monitoring systems (7 day rolling average)	MFC–3M–2004, ANSI/ASME MFC–4M–1986, ASME MFC–6M–1998, ASME/ANSI MFC–7M–1987, ASME MFC–11M–2006, ASME MFC–14M–2003, ASME MFC–18M–2001, AGA Report No. 3, Part 1, AGA Report No. 3, Part 2, AGA Report No. 11, AGA Report No. 7, API Manual of Petroleum Measurement Standards, Chapter 22, Section 2, ANSI/ASME–MFC–5M–1985, ASME/ANSI MFC–9M–1988, ASME MFC–16–2007, ASME MFC–22–2007, ISO 8316, ASTM D240–02, ASTM D1826–94, ASTM D1945–03, ASTM D1946–90, ASTM D3588–98, ASTM D4809–06, ASTM D4891–89, GPA 2172–09 • FCCU & FCU subject to a PM limit: continuous parameter monitor systems, bag leak detection system, CEMS, or an instrument for continuously monitoring the opacity of emissions • FCCU & FCU subject to NOx, SO_2 or CO limit: CEMS • Sulfur recovery plants subject to SO_2, reduced sulfur compounds, or H_2S limit: CEMS	monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel (averaged over one hour) or CEMS consisting of NOx and O2 monitors for stationary gas turbines that commenced construction, reconstruction, or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NOx emissions (averaged	(hourly average) • Annual performance tests or continuous monitoring for turbines without water or steam injection. • Monitor the total sulfur content of the fuel being fired.				

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		NOx and ammonia CEMS and without CO CEMS: every 12 months; units with ammonia CEMS and without NOx or CO CEMS: quarterly. Source test methods: South Coast AQMD methods 100.1, 7.1, 10.1, 207.1, any other approved test method determined to be equivalent and approved by the Executive Officer and either the California Air Resources Board or U.S. EPA. Diagnostic emissions checks pursuant to South Coast AQMD Combustion Gas Periodic Monitoring Protocol every 365 days or 8760 operating			• Fuel gas combustion devices subject to a SO_2 or H_2S limit: CEMS • Flare with H_2S limit: CEMS • Process heaters with a NOx limit: CEMS • Process heaters with a mass based or heating value based limit NOx limit: Fuel gas flow and fuel oil flow monitors • CPMS flow monitoring for flares • CEMS to measure total reduced sulfur for flares	over one hour) • Monitor the total sulfur content of the fuel being fired					

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		hours, whichever occurs later, for units required to source test every 36 months									
Reporting	Notification of bypass events to conduct catalyst maintenance and scheduled startups	Source tests and reports of excess emissions	• Daily electronic reporting for major sources • Monthly emissions report for major sources • Quarterly reporting for large sources and process units • Quarterly Certification of Emissions Report and Annual Permit Emissions Program report for all units • Breakdowns which result in an applicable rule or permit violation	Semi-annual reports of excess emissions and monitor downtime. Notification of compliance selection choice for FCCU catalyst regenerators, notification of initial startup	Semi- annual reports of excess emissions and monitor downtime. Notification of the specific monitoring provisions the owner or operator intends to comply with.	Semi-annual reports of excess emissions and monitor downtime	Semi-annual reports of excess emissions and monitor downtime. Annual performance test results.	Performance test results, notification of the initial startup, design heat input capacity, fuels to be combusted, a copy of any federally enforceable requirement that limits the annual capacity factor, annual capacity factor, emerging technology used for SO2 emissions; reports of excess emissions	Performance test results, performance evaluation of the CEMS and/or COMS, excess emission reports, notification of the date of construction, reconstruction, and startup, design heat input capacity, fuels to be combusted, annual capacity factor, emerging technology used for SO_2 emissions	None	Semi-annual reports of excess emissions and monitor downtime
Recordkeeping	Operating log, list of scheduled startups, list of planned maintenance shutdowns for the next 5 years for units with bypasses, and	Operating log, CEMS data, mass emissions, calculated emission rate, source test reports, diagnostic emission	• Maintenance & emission records, source test reports, RATA reports, audit reports and fuel meter calibration	Performance testing; emission rates; monitoring data; CEMS audits and checks; occurrenc	Performance testing; emission rates; monitoring data; CEMS audits and checks; occurrence and duration of any SSM; flare management plan; conformance with bag leak detection system O&M; bag leak	Performance testing; emission rates; monitoring data; CEMS audits and checks; occurrenc	Performance testing; emission rates; monitoring data; CEMS audits and checks; occurrence	Performance testing; emission rates; daily records of the amounts of each fuel combusted; calculations of the annual capacity factor for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste; nitrogen content; opacity; hours of operation. Records are	Performance testing; emission rates; monitoring data; CEMS audits and checks; fuel supplier certification;	None	Performance testing; emission rates; monitoring data; CEMS audits and

Rule Element	PR 429.1	PR 1109.1	RECLAIM	CFR Title 40, Vol. 7, Part 60, Subpart J	CFR Title 40, Vol. 7, Part 60, Subpart Ja	CFR, Title 40, Vol. 7, Part 60, Subpart GG	CFR, Title 40, Vol. 8, Part 60, Subpart KKKK	CFR, Title 40, Vol. 7, Part 60, Subpart Db	CFR, Title 40, Vol. 7, Part 60, Subpart Dc	CFR, Title 40, Vol. 7, Part 60, Subpart Cd	CFR, Title 40, Vol. 7, Part 60, Subpart H
	emissions data shall be maintained onsite for 5 years. Documentation from the manufacturer of the minimum operating temperature of NOx post-combustion control equipment.	checks, logs of startups, shutdowns, breakdowns, maintenance, service, tuning, and any other information required by this rule, annual throughput, burner replacement records, post-combustion control replacement/installation records	records for Annual Permit Emissions Program • Records shall be maintained for 3 years (5 years if Title V) except data gathered or computed for intervals < 15 minutes shall be maintained for a minimum of 48 hours	e and duration of any startup, shutdown, or malfunction	detection system alarms and actions; FCCU & FCU coke-burn off rate and hours of operation; records of emissions > 500 lbs SO_2; qualification for exemptions; time periods during which the sulfur pit vents were not controlled and measures taken to minimize emissions during these periods	e and duration of any startup, shutdown, or malfunction	and duration of any startup, shutdown, or malfunction	required to be maintained for 2 years.	daily fuel combustion. Records are required to be maintained for 2 years.		checks; occurrence and duration of any startup, shutdown, or malfunction

APPENDIX A: LIST OF AFFECTED FACILITIES

Table A-1: Facilities Affected by PR 429.1

Facility ID	Facility Name
148236	Air Liquide Large Industries U.S., LP
3417	Air Prod & Chem Inc.
101656	Air Products and Chemicals, Inc.
187165	AltAir Paramount, LLC
800030	Chevron Products Co.
180908	Eco Services Operations Corp.
800080	Lunday-Thagard Co DBA World Oil Refining
171107	Phillips 66 Co/LA Refinery Wilmington Pl
171109	Phillips 66 Company/Los Angeles Refinery
174591	Tesoro Ref & Mktg Co LLC, Calciner
174655	Tesoro Refining & Marketing Co, LLC
151798	Tesoro Refining and Marketing Co, LLC
800436	Tesoro Refining and Marketing Co, LLC
181667	Torrance Refining Company LLC
800393	Valero Wilmington Asphalt Plant
800026	Ultramar Inc

APPENDIX B – RESPONSES TO PUBLIC COMMENTS

Public Workshop Comment

Public Workshop Commenter #1: Oscar Espino Padron – Earthjustice

The commenter expressed the following:

a. Startup and shutdown exemptions are inconsistent with the Clean Air Act.
b. There is no incentive for facilities to not startup or shutdown in PR 429.1, such as a fee.
c. PR 429.1 provision for facilities to take all reasonable and prudent steps to minimize emissions during startup and shutdown is not specific.

Staff Response to Public Commenter #1:

a. PR 429.1 is consistent with U.S. EPA SSM policies for compliance with the Clean Air Act. U.S. EPA's 2015 startup, shutdown, and malfunction (SSM) policy states that state implementation plan emission limitations do not need to be numerical in format and may be composed of a combination of numerical limitations, specific technological control requirements and/or work practice requirements, with each component of the emission limitation applicable during a defined mode of source operation. PR 429.1 contains specific technological control requirements and work practice requirements during a defined mode of source operation (i.e., startup and shutdown), as well as limitations to the duration and severity of startup and shutdown events, pursuant to U.S. EPA policy guidance for startup and shutdown provisions.
b. Facilities are incentivized to limit their startups and shutdowns because they cannot fully operate the unit. Proposition 26 prevents the South Coast AQMD from imposing a fee in these circumstances unless there is an alternative compliance option.
c. Staff included specific examples of reasonable and prudent steps to minimize emissions during startup and shutdown in Chapter 2 of the staff report. This provision is consistent with general duty provisions described in U.S. EPA's 2015 SSM policy and similar provisions in South Coast AQMD permits to operate.

Email Comments

Email Comment #1: Robert Brown – Eco Services Operations Corporation

The exemption for pilots that was included in the pre-preliminary draft rule language is missing from the preliminary draft rule language.

Staff Response to Email Comment #1:

Staff removed the exemption from PR 429.1 initially because PR 1109.1 added an exemption for boilers and process heaters operating only the pilot from PR 1109.1 concentration~~emission~~ limits and the applicable rolling average. Staff recognizes that an exemption for pilots from PR 429.1 duration limits and certain recordkeeping requirements is still needed and added the exemption back into PR 429.1.

Email Comment #2: Chris Drechsel – Tesoro Refining & Marketing Company LLC

The email expressed the following:

a. 48 hours is the appropriate startup and shutdown duration limit for boilers and process heaters without NOx post-combustion control equipment, with the exception of FCCU feed preheaters, due to potential process safety issues.
b. The FCCU feed pre-heater is integrated with FCCU and is complex startup process. MPC requests 120 hours for startup and shutdown for the FCCU feed pre-heater.
c. Cogeneration gas turbines with SCRs require additional time for startup and shutdown for the catalyst to get up to temperature. MPC requests an 8 hour startup and shutdown duration limit which is consistent with existing permit conditions.
d. MPC proposes edits to startup and shutdown definitions because the appropriate indication of startup is fuel, and all combustion devices, including FCCUs use fuel. The circulation of air in the FCCU without combustion and the introduction of feed or H2 without fuel does not produce NOx emissions.

   STARTUP means the time period that begins when a NOx emitting unit combusts fuel, after a period of zero fuel flow ~~or and zero feedstock~~, ~~or when combustion/circulation air is introduced if the unit does not use fuel for combustion,~~ and ends when the flue gas temperature reaches the minimum operating temperature of the NOx post-combustion control equipment and reaches stable conditions, or when the time limit specified in Table 1 is reached~~, whichever is sooner~~.

   SHUTDOWN means the time period that begins when an operator reduces the load or heat input, and flue gas temperatures fall below the minimum operating temperature of the NOx post-combustion control equipment, if applicable, and which ends in a period of zero fuel flow ~~or zero feedstock, or when combustion/circulation air flow ends if the unit does not use fuel for combustion~~.

Staff Response to Email Comment #2:

a. See response to Comment 2-6.
b. See response to Comment 2-6.
c. See response to Comment 2-7.
d. The time that a unit is complying with the NOx and CO <u>concentration</u>~~emission~~ limits in Rule 1109.1 during a startup or shutdown does not count toward the startup and shutdown duration limits specified in Table 1. Staff did not change the startup or shutdown definition.

Comment Letters[5]

Comment Letter #1: Nanette Diaz Barragan – U.S. Representative, California 44th District

No exemptions for refineries during startup, shutdown, and malfunction periods. Refineries must be held accountable to the standards of Proposed Rule 1109.1 during non-compliance periods that are a result of inadequate equipment maintenance, operator error, or other negligence. These exemptions would provide an incentive to pollute without limitations during equipment startup and shutdown.

Staff Response to Comment Letter #1

Startup, shutdown, and malfunction (SSM) events are unavoidable. Often units are shutdown for maintenance to ensure the unit can properly operate. During startup and shutdown periods, units are not operating at stable conditions. Although NOx concentration levels may be higher during startup and shutdown, the NOx mass emissions are not necessarily higher because the flow of emissions through the stack are lower. Many air pollution control devices are subject to technical, operational, or safety constraints that require the unit to follow specific protocols when starting up and shutting down to prevent damaging the unit or its components and to ensure safe operation.

PR 429.1 has specific time periods in which a unit is exempt from PR 1109.1 concentration~~emission~~ limits. PR 429.1 is designed to minimize the emissions during startup and shutdown, while recognizing that it takes time to reach stable conditions. Some control technologies cannot achieve reductions until specific temperatures are reached and as noted in its 2015 Policy document[6], the U.S. EPA "recognize that some control equipment cannot be operated at all or in the same manner during every mode of normal operations." U.S. EPA's 2015 SSM policy states that SIP emission limitations may include other technological control requirements, or work practice requirements during startup and shutdown, so long as those components of the emission limitations meet applicable federal CAA requirements. As such, Proposed Rule 429.1 limits the duration (in hours) of the startup and shutdown event, as well as the number of scheduled startups per year. It also requires the owner or operator to take all reasonable and prudent steps to minimize emissions during startup and shutdown. PR 429.1 does not exempt an operator from the PR 1109.1 concentration~~emission~~ limits for longer than the time to reach stable conditions and the minimum operating temperature of the NOx post-combustion control equipment.

Provisions for equipment breakdowns or malfunctions are addressed by Rule 430 – Breakdown Provisions. Rule 430 does not provide coverage for rule violation directly resulting from operator error, neglect, or improper operation or maintenance procedures.

[5] Staff only included comments related to startup and shutdown in the PR 429.1 Staff Report. The full comment letters for Comment Letters #1, 3, and 4 are included in the PR 1109.1 Staff Report.
[6] 2015 SSM Policy | U.S. EPA

Comment Letter #2:

WSPA

Patty Senecal
Senior Director, Southern California Region

September 17, 2021

Michael Morris
Manager, Planning and Rules
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Via e-mail at: mmorris@aqmd.gov

Re: SCAQMD Proposed Rule 429.1, Startup and Shutdown Provisions at Petroleum Refineries and Related Operations
WSPA Comments on PR 429.1 Language (August 20, 2021 version)

Dear Mr. Morris,

Western States Petroleum Association (WSPA) appreciates the opportunity to participate in the Working Group Meetings (WGMs) for South Coast Air Quality Management District (SCAQMD or District) Regional Clean Air Incentives Market (RECLAIM) Transition, Proposed Rule 1109.1 (PR1109.1), Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations, and the related rulemaking for Proposed Rule 429.1 (PR429.1), Startup and Shutdown Provisions at Petroleum Refineries and Related Operations. These rulemakings are being undertaken to transition facilities in the RECLAIM program for NO_X emissions to a command-and-control structure (i.e., the "RECLAIM Transition Project"). WSPA is a non-profit trade association representing companies that explore for, produce, refine, transport, and market petroleum, petroleum products, natural gas, and other energy supplies in five western states including California. WSPA has been an active participant in air quality planning issues for over 30 years. WSPA-member companies operate petroleum refineries and other facilities in the South Coast Air Basin that are within the purview of the RECLAIM Program administered by the SCAQMD and will be impacted by the RECLAIM Transition Project.

SCAQMD released revised preliminary draft rule language for PR429.1 on August 20, 2021.[1] WSPA offers the following comments on the draft rule language.

1. **PR 429.1 (a): Section (a) states that the purpose of the rule is to limit emissions of NOx and CO during periods of startup and shutdown from units at petroleum refineries and facilities with related operations. This is inadequate to address refinery needs for maintenance and malfunction.**

   As currently drafted, PR429.1 addresses operations during periods of startup and shutdown for refinery equipment. But with the exception of SCR catalyst maintenance, maintenance activities for refinery equipment are not included in the stated purpose of the proposed rule. The rule also does not address equipment breakdowns (i.e., malfunctions). Current Rule 430, Breakdown Provisions, does not provide adequate provisions for refining equipment. For this reason, WSPA suggests that a new section be included in the rule to explicitly address 2-1

[1]Proposed Rule 429.1, Startup and Shutdown Provisions at Petroleum Refineries and Related Operations: Preliminary Draft Rule Language. Available at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/429.1/rule-429-1-pdrl-pw.pdf?sfvrsn=4. Accessed: September 2021.

maintenance and breakdown provisions for refinery equipment. The Purpose should be restated as follows: 2-1 cont.

The purpose of this rule is to limit emissions of oxides of nitrogen (NOx) and carbon monoxide (CO) during periods of startup, ~~and~~ shutdown, maintenance, and malfunctions (SSMM) from units at petroleum refineries and facilities with ~~related~~ operations related to petroleum refineries.

2. **PR 429.1(c)(2): The definition of "Catalyst Maintenance" should be revised to include any ancillary equipment to the SCR system, such as the ammonia injection system or induced draft fans. WSPA recommends that the language be updated as follows:** 2-2

   CATALYST MAINTENANCE means conditioning, repairing, or replacing the catalyst or ancillary equipment in NOx post-combustion control equipment associated with a unit which has a bypass stack or duct that exists prior to [Date of Adoption].

3. **PR 429.1(c): Some gas turbines need to be tuned multiple times per year as part of regular scheduled maintenance required by the manufacturer. In the event that tuning requires a startup or shutdown, units will require relief from Proposed Rule 1109.1 concentration limits if a startup or shutdown is necessary.** 2-3

   WSPA suggests the definition of "TUNING" from Rule 1134 be added to Rule 429.1:

   TUNING is adjusting, optimizing, rebalancing, or other similar operations to a stationary gas turbine or an associated control device or otherwise as defined in the South Coast AQMD Permit to Construct or Permit to Operate. Tuning does not include normal operations to meet load fluctuations.

4. **PR 429.1(d): WSPA recommends the following changes.** 2-4

   - PR429.1(d)(1)
     - As discussed above, cogeneration turbines need to be tuned multiple times per year as part of regular scheduled maintenance. If a gas turbine requires shutdown for tuning, it will not be able to meet the concentration limits in Proposed Rule 1109.1. WSPA recommends that the language in Section (d)(1) be updated as follows:

       (1) *An owner or operator of a unit is not subject to the NOx and CO emission limits and the applicable rolling average provisions pursuant to Rule 1109.1 during startup, shutdown, tuning maintenance events, and catalyst maintenance events.*

   - PR429.1(d)(2)
     - Section (d)(2) limits the duration of startup and shutdown events. This section should include stated duration limits for equipment commissioning periods. SCAQMD often includes commissioning duration when issuing Permits to Construct, and this should be reflected in the rule language. 2-5
     - The proposed durations for process heaters, boilers, and SMR heater startup and shutdown events are insufficient to accommodate these activities. The District should confer with facilities to understand what adjustments are 2-6

needed. The standards established in the rule must be adequate to allow all affected units to comply. 2-6 cont.

- Gas turbines with NOx post-combustion control equipment have similar issues to boilers and process heaters with respect to the necessary time allowance to meet NOx emission limits. WSPA requests that Table 1 of (d)(2) be changed such that a gas turbine with NOx post-combustion control equipment is subject to the same 48-hour time allowance as boiler and process heaters with NOx post-combustion control equipment 2-7

- PR429.1(d)(7)
  - Paragraph (d)(7) is an operating requirement for post-combustion control equipment if the temperature of the exhaust gas to the inlet of the control equipment "… is greater than or equal to the minimum operating temperature." Because operating temperature fluctuates during startup, WSPA observes that, at times, the minimum temperature may be initially reached for a very short duration and then fall below that minimum temperature before again rising to a minimum temperature until a stabilized minimum temperature is reached. For this reason, WSPA requests that the aforementioned phrase be changed to "… is greater than or equal to the minimum operating and stable temperature." 2-8

- PR 429.1(d)(8) – The proposed rule language significantly restricts the ability to use bypass stacks. The purpose of the bypass stack is to allow conditioning, repair, and replacement of SCR catalyst <u>or ancillary equipment associated with the NOx post-combustion control equipment</u> in order to meet the BARCT limit. Therefore, the following adjustments are requested.

  - (d)(8)(B)
    - This section limits the use of a bypass stack to 200 hours in a rolling three-year cycle. This time period appears to be arbitrary and is insufficient for catalyst changeouts on some units. WSPA recommends that the duration for use of the bypass stack be extended to 14 days per year. 2-9

  - (d)(8)(C)
    - This section requires that the unit be operated at the minimum safe operating rate of the unit when the NOx post-combustion control equipment is bypassed. The minimum safe operating rate should be in reference to the process unit, not the combustion device. The minimum rate or turndown of a combustion device could be lower than the safe operating rate of the process unit and would cause the unit to shut down. The operation of the combustion device will be dictated by the operating rate of the process unit. WSPA suggests that the language be updated as follows: 2-10

      Operate the unit at the minimum safe operating rate of the process unit when the NOx post-combustion control equipment is bypassed.

  - (d)(8)(D)

- This section requires that a facility submit documentation from the manufacturer of the minimum safe operating rate for the unit being bypassed. The minimum safe operating rate is determined by the refinery, not the manufacturer. WSPA recommends that the language in Section (d)(7)(d) be stricken from the rule. 2-11

5. PR 429.1 (f)(2): WSPA recommends the following.

- This section requires that an owner or operator of a unit maintain on-site documentation from the manufacturer of the minimum operating temperature of the NOx post-combustion control equipment and make the information available to SCAQMD upon request. Refinery permits already include conditions specifying minimum temperature for ammonia injection which are equipment-specific. WSPA suggests that the language be updated as follows: 2-12

  An owner or operator of a unit equipped with NOx post-combustion control equipment at a former RECLAIM petroleum refinery or a new petroleum refinery shall maintain on-site documentation from the manufacturer of the minimum operating temperature of the NOx post-combustion control equipment and make this information available to the South Coast AQMD upon request *unless the minimum temperature requirement is listed in the Permit to Operate*.

6. PR 429.1(g): WSPA requests that the following exemptions be added to the rule:

- The SSMM provisions listed in PR429.1 should be a backstop for units that do not have SSMM provisions included in their Permits to Operate. The rule should therefore defer to equipment specific SSMM conditions where listed in the permit. WSPA recommends that an exemption be added to the rule to address equipment with existing SSMM permit conditions. 2-13
- PR429.1(g)(1) – This section provides an exemption from the duration limits during certain commissioning and maintenance activities. An exemption should be added to the rule to address duration limits related to tuning on cogeneration turbines. WSPA recommends revising the language in Section (g)(1) as follows: 2-14

  (1) An owner or operator of a unit at a former RECLAIM petroleum refinery or a new petroleum refinery shall be exempt from the requirements of paragraph (d)(2) during the following…
  (E) Tuning Maintenance Activities

- Cogeneration units are subject to North American Electric Reliability Corporation (NERC) standards, which specify reliability standards for power generation facilities that supply power to the public. These standards include the requirement to maintain their equipment in good working order, including the obligation to conduct electrical testing following any upgrades or repairs made to the cogeneration unit's safety and control systems (e.g., protection relay and excitation control systems). These tests are required to ensure that the systems have been functionally tested to prevent any process safety or reliability issues. Some testing must occur at different electrical loads that can only occur during the startup phase. The testing duration ranges from 4 to 12 hours depending on the complexity of the testing. As this testing is required to ensure 2-15 the safety and reliability of the system, WSPA requests that this testing be categorically excluded from the time limitations in paragraph (d)(2) by including the following: 2-15 cont.

- Adding the following exemption as a new subparagraph to paragraph (g)(1):

  (g)(1)(E) Electrical testing associated with commissioning of cogeneration control systems following upgrades or repairs.

  and

- Adding the definition of gas turbine which incorporates the term "cogeneration" from subdivision (c) of PR 1109.1 to PR429.1(c). 2-16

WSPA appreciates the opportunity to provide these comments related to PR429.1. We look forward to continued discussion of this important rulemaking. If you have any questions, please contact me at (310) 808-2144 or via e-mail at psenecal@wspa.org.

Sincerely,

Patty Senecal

Cc: Wayne Nastri, SCAQMD
Susan Nakamura, SCAQMD

Western States Petroleum Association 1415 L Street, Suite 900, Sacramento, CA 95814 805.701.9142 wspa.org

Staff Response to Comment Letter #2:

Response to Comment 2-1:
The purpose of PR 429.1 is not to provide an exemption or establish requirements for other maintenance activities not specified in the rule. Equipment breakdowns from units at petroleum refineries and facilities with related operations to refineries will be regulated under Rule 430 – Breakdown Provisions. Rule 430 contains similar breakdown provisions to Rule 2004, which refineries are currently subject to.

Response to Comment 2-2:
The catalyst maintenance definition in PR 429.1 is intentionally narrow to not include activities that are regulated under Rule 430 – Breakdown Provisions.

Response to Comment 2-3:
A unit is not subject to Rule 1109.1 NOx or CO concentration~~emission~~ limits or applicable rolling average provisions during startup or shutdown. Therefore, in the event that a turbine needs to be shutdown and subsequently startup for tuning, relief from Rule 1109.1 concentration~~emission~~ limits is already provided in PR 429.1. However, staff recognizes that tuning typically occurs when the unit is in operation.

Staff updated the rule language to include a definition of tuning and exemptions from PR 1109.1 concentration~~emission~~ limits and applicable rolling average provisions during tuning provided that tuning requirements are included in the South Coast AQMD Permit to Construct or Permit to Operate.

Response to Comment 2-4:
See response to Comment 2-3.

Response to Comment 2-5:
Requirements during commissioning, including duration limits, will continue to be regulated by the South Coast AQMD permitting process, rather than by PR 429.1. PR 429.1 provides an exemption from Rule 1109.1 concentration~~emission~~ limits and applicable rolling average provisions during commissioning, provided that a South Coast AQMD Permit to Construct or Permit to Operate specifies requirements during commissioning. The PR 429.1 exemption during commissioning only applies for the duration specified in the South Coast AQMD Permit to Construct or Permit to Operate.

Response to Comment 2-6:
Staff met with facilities regarding their concerns with the proposed startup and shutdown duration limits and requested supporting documentation, such as CEMS data, to determine the duration limits needed for startup and shutdown. Staff increased the startup and shutdown duration limits for process heaters without NOx post-combustion control equipment to 24 hours and created a new category for FCCU feed pre-heaters based on supporting facility documentation. Staff also added

an exemption from the startup and shutdown duration limits specified in paragraph (d)(2) during water freeing for a maximum of 24 hours. Staff did not receive sufficient documentation that would demonstrate the need for increased duration limits for boilers or SMR heaters.

Response to Comment 2-7:

Staff met with the known affected facility requesting increased startup and shutdown duration limits for gas turbines with NOx post-combustion control equipment. The facility provided documentation that a 4 hour startup and shutdown limit is needed for gas turbines with NOx post-combustion control equipment. Staff updated PR 429.1 to include a 4 hour startup and shutdown limit for gas turbines with NOx post-combustion control equipment.

Response to Comment 2-8:

Staff recognizes that there may be temperature fluctuations during startup and updated the rule language.

Response to Comment 2-9:

Staff contacted multiple industry representatives involved in the manufacture and design of catalyst systems at refineries to establish the number of hours for catalyst maintenance. Staff has not received comment letters from any affected facilities regarding the hour limit for catalyst maintenance. Therefore, staff did not change the number of hours for catalyst maintenance allowed in PR 429.1.

Response to Comment 2-10:

Staff updated the rule language to incorporate the suggested clarification.

Response to Comment 2-11:

The proposed requirement for a facility to submit documentation from the manufacturer of the minimum safe operating rate of a unit was included for compliance verification purposes. Initially, staff proposed that the unit be operated at a percentage of the rated heat input capacity during catalyst maintenance events. Staff changed the rule language to operate the unit at the "minimum safe operating rate" at the request of WSPA. Since documentation of the minimum safe operating rate cannot be provided by the manufacturer, staff has decided to specify a percentage of the rated heat input capacity that the process unit is required to operate at or below during catalyst maintenance events. Staff established the percentage of rated heat input capacity from stakeholder information of the minimum safe operating rates.

A stakeholder clarified that the information provided for the minimum safe operating rate was based on the feed rate. Staff updated PR 429.1 subparagraph (d)(7)(C) to refer to the feed rate of the process unit rather than the rated heat input capacity, added a definition for feed rate, and removed the definition of rated heat input capacity.

Response to Comment 2-12:

Staff recognizes that documentation from the manufacturer of the minimum operating temperature of NOx post-combustion control equipment is unnecessary for units with a permit requirement specifying the temperature to operate the NOx post-combustion control equipment. Minimum operating temperature is defined in PR 429.1 as "…the minimum operating temperature specified by the manufacturer, unless otherwise defined in the South Coast AQMD permit to operate". Staff updated the rule language.

Response to Comment 2-13:
U.S. EPA has requested that startup and shutdown requirements be specified in a rule. Units are required to comply with PR 429.1 and South Coast AQMD permit conditions. A unit with a permit condition that is more stringent than PR 429.1 will continue to be regulated by the more stringent permit condition.

Response to Comment 2-14:
Tuning does not fall under the definitions of startup or shutdown, and therefore an exemption from the startup and shutdown duration limits specified in Paragraph (d)(2) is unnecessary.

Response to Comment 2-15:
Staff recognizes that there are reliability standards required by North American Electric Reliability Corporation for power generation facilities, which includes electrical testing. Staff updated the rule language to include an exemption from startup and shutdown duration limits during commissioning provided requirements are included in the South Coast AQMD Permit to Operate or Permit to Construct. The definition of commissioning in PR 429.1 includes electrical testing associated with upgrades or repairs of cogeneration gas turbines as required by North American Electric Reliability Corporation standards.

Response to Comment 2-16:
The definition of unit in PR 429.1 includes gas turbines and refers to the definitions in Rule 1109.1. Therefore, the Rule 1109.1 definition of gas turbine, which incorporates the term cogeneration, is applicable in PR 429.1.

Comment Letter #3: Steve Steach – Torrance Refining Company LLC

Rule 429.1 Comments

(c) Definitions

The definition of "CATALYST MAINTENANCE" should also include any ancillary equipment to the SCR system such as the NH3 injection system and the induced draft fan. 3-1

(d) Requirements

(d)(8) – *"An owner or operator of a unit equipped with a NOx post-combustion control equipment at a former RECLAIM petroleum refinery or a new petroleum refinery which has a stack or duct that exists prior to [Date of Adoption] that allows for the exhaust gas to bypass the NOx post-combustion control*

equipment and that elects to use a bypass to conduct catalyst maintenance shall:

> *(A) Not use a bypass if the unit is scheduled to operate continuously for less than five years between planned maintenance shutdowns of the unit;*
>
> *(B) Not use a bypass to conduct catalyst maintenance for more than 200 hours in a rolling three-year cycle;*
>
> *(C) Operate the unit at the minimum safe operating rate of the unit when the NOx post-combustion control equipment is bypassed;* 3-2
>
> *(D) Submit documentation from the manufacturer of the minimum safe operating rate for the unit being bypassed to the South Coast AQMD;"*

The term "minimum safe operating rate of the unit" should clearly refer to the Process Unit, not the combustion device. The minimum rate or turndown of a combustion device could be lower than the safe operating rate of the Process Unit and would cause the unit to shut down. The combustion device's operation will be dictated by the operating rate of the Process Unit. Further, the minimum safe operating rate is determined by the Refinery, not a manufacturer. Therefore, documentation should not be required.

(f) Recordkeeping

(f)(2) – *"An owner or operator of a unit equipped with NOx post-combustion control equipment at a former RECLAIM petroleum refinery or a new petroleum refinery shall maintain on-site documentation from the manufacturer of the minimum operating temperature of the NOx post-combustion control equipment and make this information available to the South Coast AQMD upon request."* 3-3

Refineries' Title V permits include permit conditions for specific temperatures when the injection of NH3 should begin in the SCR system for optimal NOx reduction. Therefore, this requirement should also include … "unless the minimum temperature requirement is in the Refinery's permit."

Staff Response to Comment Letter #3:

Response to Comment 3-1:
See response to Comment 2-2.

Response to Comment 3-2:
See responses to Comment 2-10 and Comment 2-11.

Response to Comment 3-3:
See response to Comment 2-12.

Comment Letter #4: Brad Levi – Tesoro Refining & Marketing Company LLC

16. Potential confusion between the RECLAIM transition and B-Cap related limits and associated calculation and monitoring methods needs to be addressed in the rule.

MPC requests clarity as to when a Facility is operating after the effective date of PR 1109.1 but before it becomes a Former RECLAIM Petroleum Refinery. Specifically, PR 429.1 addresses startup and shutdown emissions for PR 1109.1 but only applies to a Former RECLAIM Petroleum Refinery. Until a 4-1

Final Determination Notification is issued, it is unclear how a Facility is to address applicable limits that may be in effect for PR 1109.1. Relatedly, compliance with Rules 218.2 and 218.3 for CEMS is not required until a Facility becomes a Former RECLAIM Petroleum Refinery. For any limits in effect under PR 1109.1 at the Facility until it receives a Final Determination Notification, it is unclear if the Facility should follow a different set of CEMS requirements. MPC requests regulatory certainty to address the transition between RECLAIM and PR 1109.1 for compliance monitoring.

18. PR 1109.1 needs to reference and incorporate the startup and shutdown provisions in PR 429.1 and revise PR 429.1 so as to appropriately address management of startups and shutdowns.

The proposed PR 1109.1 rule does not reference PR 429.1 or otherwise clarify how startup and shutdown emissions are to be included or excluded for accounting against emission limits. Particularly, PR 1109.1 4-2~~1~~ needs to expressly state that emissions from startups and shutdowns are exempt when determining compliance with the Alternative NOx BARCT Limits and the annual mass emissions against the BARCT Emissions Targets. To remove this ambiguity, MPC requests SCAQMD add a reference or statement in PR 1109.1 excluding the emissions from startup and shutdown events in PR 429.1 for purposes of compliance with emission limits in PR 1109.1.

Regarding the proposed PR 429.1 rule itself, MPC offers the following comments to address multiple startup and shutdown activities that are required for compliance with PR 1109.1. Attachment 2 of this letter is a proposed mark-up of PR 429.1 to reflect MPC's comments.

A. Cogeneration unit electrical testing

Cogeneration units are subject to industry and electrical standards to ensure that the equipment is reliable and in good working order. This includes conducting electrical testing following any upgrades or repairs made to the cogeneration unit's safety and control systems (e.g., protection relay and excitation control 4-3~~2~~ systems). These tests are to ensure that the systems have been functionally tested to prevent process safety and reliability issues. Some testing must take place at different electrical loads that can only occur during the startup phase. The testing duration ranges from 4 to 12 hours depending on the complexity of the

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testing. As this testing is to ensure the safety and reliability of the system, MPC requests that this testing be categorically excluded from the time limitations in paragraph (d)(2) of PR 429.1 by including the following: 4-3~~2~~ cont.

- Add the following exemption as a new subparagraph (g)(1)(E) to paragraph (g)(1): *"electrical testing associated with commissioning of cogeneration control systems following upgrades or repairs."*; and

- Copy the definition of gas turbine from subdivision (c) of PR 1109.1, which incorporates the term "cogeneration." 4-4~~3~~

B. Catalyst maintenance and related activities

MPC offers the following proposed changes to address catalyst maintenance and related activities:

- Paragraph (c)(2) requires that catalyst maintenance for a Unit *"... which has a bypass stack or duct ..."* MPC requests removal of this phrase, since some combustion units have only one stack which is used for both normal operations and for catalyst maintenance activities that bypass the control equipment (i.e., the control equipment is not operable during control equipment maintenance). Paragraph (d)(8) is also revised to align with this definition. 4-5~~4~~

- The proposed definition in paragraph (c)(2) is specific only to catalyst maintenance activities and is not inclusive of other maintenance activities inherently needed for NOx post-combustion control equipment. For example, routine maintenance activities associated with a post-combustion control equipment's ammonia injection system and related components is required, which would impact emissions because ammonia is not being introduced into the control equipment during that time. MPC proposes to revise this definition to include maintenance of ancillary components in NOx post-combustion control equipment. 4-6~~5~~

- Paragraph (d)(7) is an operating requirement for post-combustion control equipment if the temperature of the exhaust gas to the inlet of the control equipment *"... is greater than or equal to the minimum operating temperature."* Operating temperature fluctuates during startup, and MPC has observed from its operations that the minimum temperature may be initially reached for a very short duration and then fall below that minimum temperature before again rising to a minimum temperature until the stabilized minimum temperature is reached. For this reason, MPC requests that the aforementioned phrase be changed to *"... is greater than or equal to the minimum operating and stable temperature."* 4-7~~6~~

- Subparagraph (d)(8)(D) requires documentation from a manufacturer of the *"minimum safe operating rate for the unit being bypassed."* The minimum safe operating rate for a Unit is a function of process safety management reviews by operations and safety staff and the application of MPC's operational safety policies and procedures to a Unit. Manufacturers will not know or have documentation of the minimum safe operating rate for a Unit. MPC requests deletion of this subparagraph. 4-8~~7~~

C. Gas turbines with NOx post-combustion control equipment

Gas turbines with NOx post-combustion control equipment have issues that are similar to boilers and process heaters with respect to the necessary time allowance to meet NOx emission limits. MPC requests 4-9~~8~~

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that Table 1 of PR 429.1 be changed such that a gas turbine with NOx post-combustion control equipment is subject to the same 48-hour time allowance as boiler and process heaters with NOx post-combustion control equipment. 4-9~~8~~ cont.

D. Two-hour duration limit in Table 1 for process heaters

Based upon a review of its procedures and practices, MPC has determined that the startup and shutdown duration limit of two hours in Table 1 is insufficient for process heaters. It is unclear in the corresponding Draft Staff Report how this hourly limit was established. From MPC's experience it is unrealistic for several process heaters that do not have post-combustion NOx control equipment to reach stable conditions in two hours such that the NOx emissions controls (i.e., ultra-low NOx burners) can effectively meet the emission limits in PR 1109.1. For example, some heaters inherently require slower warming to avoid damaging downstream equipment affected by temperature changes and thus need more than 2 hours to start up. Also, heaters with natural draft systems or several dozen burners that need to be lit during startup will make control of excess oxygen difficult at low and fluctuating firing rates, which causes higher NOx concentrations until stable conditions are reached. To ensure MPC is allotted sufficient time to allow for safe and steady startup, MPC requests additional consultation with SCAQMD to support an appropriate increase to the 2-hour duration limit currently proposed in Table 1 for process heaters. 4-10~~9~~

(Adopted November 5, 2021)
V081821

PROPOSED RULE 429.1 STARTUP AND SHUTDOWN PROVISIONS AT PETROLEUM REFINERIES AND RELATED OPERATIONS

(a) Purpose
The purpose of this rule is to limit emissions of oxides of nitrogen (NOx), while not increasing carbon monoxide (CO) emissions, during periods of startup and shutdown, from units at petroleum refineries and facilities with related operations to petroleum refineries.

Commented [A1]: Capitalize all defined terms in the rule. 4-11

(b) Applicability
The provisions of this rule shall apply to an owner or operator of units at petroleum refineries and facilities with related operations to petroleum refineries.

(c) Definitions
For the purpose of this rule, the following definitions shall apply:

(1) CASTABLE REFRACTORY means refractory that is made by curing liquid material that has been poured into a mold.

(2) CATALYST MAINTENANCE means conditioning, repairing, or replacing the catalyst or ancillary components in NOx post-combustion control equipment associated with a unit
~~which has a bypass stack or duct that exists prior to [*Date of Adoption*]~~.

(3) CATALYST REGENERATION ACTIVITIES means the procedure where air or steam is used to remove coke from the catalyst of a unit or the conditioning of catalyst prior to the startup of a unit.

(4) FACILITY WITH RELATED OPERATIONS TO PETROLEUM REFINERIES as defined in Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations.

(5) FORMER RECLAIM PETROLEUM REFINERY means a petroleum refinery or a facility with related operations to petroleum refineries, or any of its successors, that was in the Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX – Regional Clean Air Incentives Market (RECLAIM), that has received a final determination notification, and is no longer in the RECLAIM program.

PR 429.1 -1

Proposed Rule 429.1 (Cont.) **(Adopted November 5, 2021)**

(6) GAS TURBINE means an internal-combustion engine in which the expanding combustion gases drive a turbine which then drives a generator to produce electricity. Gas Turbines can be equipped with a cogeneration gas turbine that recovers heat from the Gas Turbine exhaust and can include a duct burner.

(76) MINIMUM OPERATING TEMPERATURE means the minimum operating temperature specified by the manufacturer, unless otherwise defined in the South Coast AQMD permit to operate.

(87) NEW PETROLEUM REFINERY means a petroleum refinery or a facility with related operations to a refinery that begins operation after [*Date of Adoption*].

(98) NOx POST-COMBUSTION CONTROL EQUIPMENT means air pollution control equipment which eliminates, reduces, or controls the issuance of NOx after combustion.

(109) OXIDES OF NITROGEN (NOx) EMISSIONS as defined in Rule 1109.1.

(110) PETROLEUM REFINERY as defined in Rule 1109.1.

(121) REFRACTORY DRYOUT means the initial application of heat under controlled rates to safely remove water from refractory lining as part of the curing process prior to placing the unit in service.

(132) SCHEDULED STARTUP means a planned startup that is specified by January 1 of each year.

(143) SHUTDOWN means the time period that begins when an operator reduces the load or heat input, and flue gas temperatures fall below the minimumoperating temperature of the NOx post-combustion control equipment, if applicable, and which ends in a period of zero fuel flow or zero feedstock, or when combustion/circulation air flow ends if the unit does not use fuel for combustion.

(154) STABLE CONDITIONS means that the fuel flow, fuel composition, or feedstock to a unit, or the combustion/circulation air if the unit does not use fuel for combustion, is consistent and allows for normal operations.

(165) STARTUP means the time period that begins when a NOx emitting unit combusts fuel, after a period of zero fuel flow or zero feedstock, or when combustion/circulation air is introduced if the unit does not use fuel for combustion, and ends when the flue gas temperature reaches the minimum operating temperature of the NOx post-combustion control equipment and reaches stable conditions, or when the time limit specified in Table 1 is reached, whichever is sooner.

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Proposed Rule 429.1 (Cont.) **(Adopted November 5, 2021)**

(1<u>7</u>~~6~~) UNIT means equipment that is subject to Rule 1109.1 which includes boilers, flares, fluid catalytic cracking units (FCCUs), gas turbines, petroleum coke calciners, process heaters, steam methane reformer heaters, sulfuric acid furnaces, sulfur recovery units/tail gas incinerators (SRU/TG incinerators), and vapor incinerators, as defined in Rule 1109.1, requiring a South Coast AQMD

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Proposed Rule 429.1 (Cont.) **(Adopted November 5, 2021)**

permit and not required to comply with a NOx emission limit by other South Coast AQMD Regulation XI rules.

(d) Requirements

(1) An owner or operator of a unit is not subject to the NOx and CO emission limits and the applicable rolling average provisions pursuant to Rule 1109.1 during startup, shutdown, ~~and~~ catalyst maintenance events, and maintenance events related to ammonia injection system equipment.

(2) The owner or operator of a unit at a former RECLAIM petroleum refinery or a new petroleum refinery shall not exceed the time allowances specified in Table 1 when emissions from the unit exceed the NOx or CO emission limits established in Rule 1109.1 during a startup or shutdown.

TABLE 1: STARTUP AND SHUTDOWN DURATION LIMITS

Unit Type	Time Allowance When Emissions Exceed Rule 1109.1 Emission Limits (Hours)
Boilers, Gas Turbines, and Process Heaters without NOx Post-Combustion Control Equipment, ~~Gas Turbines,~~ Flares, Vapor Incinerators without NOx Post-Combustion Control Equipment or Castable Refractory	2
Vapor Incinerators with NOx Post-Combustion Control Equipment, Vapor Incinerators with Castable Refractory	20
Boilers, Gas Turbines, and Process Heaters with NOx Post- Combustion Control Equipment, Steam Methane Reformer Heaters, Sulfuric Acid Furnaces	48
Steam Methane Reformers with Gas Turbine	60
FCCUs, Petroleum Coke Calciners, SRU/TG Incinerators	120

Commented [A2]: See comment letter for concerns with this duration limit.

(A) An owner or operator of a unit at a former RECLAIM petroleum refinery or a new petroleum refinery shall not allow a startup to last

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Proposed Rule 429.1 (Cont.) **(Adopted November 5, 2021)**

longer than the time to reach stable conditions and to reach the minimum operating temperature of the NOx post-combustion control equipment, if applicable.

(3) An owner or operator of a boiler, flare, gas turbine, process heater, steam methane reformer heater, sulfuric acid furnace, or vapor incinerator at a former RECLAIM petroleum refinery or a new petroleum refinery shall not exceed ten scheduled startups per calendar year for each unit.

(4) An owner or operator of a FCCU, petroleum coke calciner, or SRU/TG incinerator at a former RECLAIM petroleum refinery or a new petroleum refinery shall not exceed three scheduled startups per calendar year for each unit.

(5) An owner or operator of a unit at a former RECLAIM petroleum refinery or a new petroleum refinery shall take all reasonable and prudent steps to minimize emissions during startup and shutdown .

(6) An owner or operator of a unit at a former RECLAIM petroleum refinery or a new petroleum refinery equipped with NOx post-combustion control equipment shall install and maintain an annually calibrated temperature measuring device at the inlet of the NOx post-combustion control equipment.

(7) An owner or operator of a unit at a former RECLAIM petroleum refinery or a new petroleum refinery shall operate the NOx post-combustion control equipment, if applicable, including the injection of any associated chemical reagent into the exhaust stream to control NOx, if the temperature of the exhaust gas to the inlet of the NOx post-combustion control equipment is greater than or equal to the minimum operating and stable temperature.

(8) An owner or operator of a unit equipped with a NOx post-combustion control equipment at a former RECLAIM petroleum refinery or a new petroleum refinery ~~which has a stack or duct that exists prior to [*Date of Adoption*] that~~ allows for the exhaust gas to bypass the NOx post-combustion control equipment and that elects to use a bypass to conduct catalyst maintenance shall:

(A) Not use a bypass if the unit is scheduled to operate continuously for less than five years between planned maintenance shutdowns of the unit;

(B) Not use a bypass to conduct catalyst maintenance for more than 200 hours in a rolling three-year cycle;

(C) Operate the unit at the minimum safe operating rate of the unit when the NOx post-combustion control equipment is bypassed;

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Proposed Rule 429.1 (Cont.) **(Adopted November 5, 2021)**

~~(D) Submit documentation from the manufacturer of the minimum safe operating rate for the unit being bypassed to the South Coast AQMD;~~

(~~E~~D) Notify the South Coast AQMD by calling 1-800-CUT-SMOG at least 24 hours prior to bypassing the NOx post-combustion control equipment. This notification shall contain the date and estimated time and duration that the NOx post-combustion control equipment will be bypassed; and

(~~F~~E) Continuously monitor NOx and CO emissions with a certified Continuous Emissions Monitoring System (CEMS) pursuant to Rule 218.2 – Continuous Emission Monitoring System: General Provisions and Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications or a contractor approved under the South Coast AQMD Laboratory Approval Program (LAP).

(e) Notification

(1) An owner or operator of a unit at a former RECLAIM petroleum refinery or a new petroleum refinery shall notify the South Coast AQMD by calling 1-800-CUT-SMOG at least 24 hours prior to a scheduled startup. The notification shall contain the date and time the scheduled startup will begin.

(f) Recodkeeping

(1) An owner or operator of a unit at a former RECLAIM petroleum refinery or a new petroleum refinery shall maintain the following records on-site for 5 years and make this information available to the South Coast AQMD upon request:

(A) An operating log for startup, shutdown, refractory dryout, catalyst maintenance, catalyst regeneration activities, initial commissioning of a unit, and initial commissioning of NOx post-combustion control equipment, which contains the date, time, duration, and reason for each event;

(B) A list of scheduled startups;

(C) A list of planned maintenance shutdowns for the next 5 years for each unit equipped with a bypass stack or duct that exists prior to [*Date of Adoption*]; and

(D) NOx and CO emissions data collected pursuant to subparagraph (d)(8)(F).

(2) An owner or operator of a unit equipped with NOx post-combustion control equipment at a former RECLAIM petroleum refinery or a new petroleum

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Proposed Rule 429.1 (Cont.) **(Adopted November 5, 2021)**

refinery shall maintain on-site documentation from the manufacturer of the minimum operating temperature of the NOx post-combustion control equipment and make this information available to the South Coast AQMD upon request.

(g) Exemptions

(1) An owner or operator of a unit at a former RECLAIM petroleum refinery or a new petroleum refinery shall be exempt from the requirements of paragraph (d)(2) during the following:

(A) Refractory dryout;

(B) Catalyst regeneration activities;

(C) Initial commissioning of a unit; ~~and~~

(D) Initial commissioning of NOx post-combustion control equipment; and~~.~~

(E) Electrical testing associated with commissioning of cogeneration control systems following upgrades or repairs~~Initial commissioning of NOx post-combustion control equipment.~~

~~(D)~~

(2) An owner or operator of a unit at a former RECLAIM petroleum refinery or a new petroleum refinery with a permit condition before [*Date of Adoption*] which allows the use of a bypass to conduct maintenance shall be exempt from the requirements of paragraph (d)(8).

Staff Response to Comment Letter #4:

Response to Comment 4-1:
PR 429.1 applies to an owner or operator of units at petroleum refineries and facilities with related operations to petroleum refineries. The exemption from NOx and CO limits in Rule 1109.1 specified in paragraph (d)(1) is applicable while a facility is in RECLAIM and once it becomes a former RECLAIM facility. Many of the requirements in PR 429.1 do not apply until a facility becomes a former RECLAIM facility because RECLAIM facilities are required to reconcile emissions from startup and shutdown events through the use of RTCs.

Response to Comment 4-2~~1~~:
Staff is following the 2015 guidance on startup and shutdown provisions from U.S. EPA. U.S. EPA informed staff of the possibility that it's policy guidance for startup and shutdown provisions may be updated. Staff decided to bifurcate all startup and shutdown references and requirements from PR 1109.1 and instead create PR 429.1 to address U.S. EPA policy guidance on those topics. A direct reference in PR 1109.1 to PR 429.1 is unnecessary as all adopted rules are equally applicable and PR 429.1 refers to PR 1109.1.

Response to Comment 4-3~~2~~:
See response to Comment 2-15.

Response to Comment 4-4~~3~~:
See response to Comment 2-16.

Response to Comment 4-5~~4~~:
Staff recognizes that some combustion units may have only one stack or duct used for both normal operations and for bypassing the NOx post-combustion control equipment. Paragraph (c)(2) includes units with bypass stacks or ducts that are used solely for bypassing the NOx post-combustion control equipment and units with bypass stacks or ducts that are used for both normal operations and for bypassing the NOx post-combustion control equipment. Staff is not removing this phrase because it specifies that the catalyst maintenance provision in PR 429.1 only applies to units that have a bypass stack or duct that exists prior to [*Date of Adoption*].

Response to Comment 4-6~~5~~:
See response to Comment 2-2.

Response to Comment 4-7~~6~~:
See response to Comment 2-8.

Response to Comment 4-8~~7~~:
See response to Comment 2-11.

Response to Comment 4-9~~8~~:
See response to Comment 2-7.

Response to Comment 4-10~~9~~:
See response to Comment 2-6.

Response to Comment 4-11:
Staff does not feel it is necessary to capitalize all terms.

ATTACHMENT S

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Staff Report

Proposed Amended Rule 1304 – Exemptions
Proposed Amended Rule 2005 – New Source Review for RECLAIM

November 2021

Deputy Executive Officer
Planning, Rule Development, and Area Sources
Sarah L. Rees, Ph.D.

Assistant Deputy Executive Officer
Planning, Rule Development, and Area Sources
Susan Nakamura

Planning and Rules Manager
Planning, Rule Development, and Area Sources
Michael Morris

Author:	Lizabeth Gomez	Air Quality Specialist
Contributors:	Jason Aspell	Deputy Executive Officer
	Bhaskar Chandan	Senior Air Quality Engineering Manager
	Mitch Haimov	Senior Air Quality Engineering Manager
	George Illes	Supervising Air Quality Engineer
	Mika Macfarlane	Air Quality Engineer I (former)
	David Ono	Senior Air Quality Engineering Manager
	Thomas Truppi	Air Quality Engineer II
	Tran Vo	Supervising Air Quality Engineer
Reviewed by:	Barbara Baird	Chief Deputy Counsel
	Brian Tomasovic	Principal Deputy District Counsel
	Uyen-Uyen Vo	Program Supervisor
	William Wong	Principal Deputy District Counsel

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INTRODUCTION

New Source Review (NSR) is a regulatory pre-construction permitting program required by the federal and state Clean Air Acts to ensure that emission increases from new and modified sources do not interfere with the progress towards meeting the National Ambient Air Quality Standards (NAAQS) and state ambient air quality standards, while ensuring that future economic growth and facility modernization in the South Coast Air Quality Management District (South Coast AQMD) are not unnecessarily restricted. South Coast AQMD has two NSR programs for nonattainment pollutants: Regulation XIII – New Source Review (Regulation XIII) and Rule 2005 – New Source Review for RECLAIM (Rule 2005). Regulation XIII and Rule 2005 apply to pollutants that have been designated as nonattainment for a national or state ambient air quality standard. Additionally, South Coast AQMD has partial delegation of the federal major NSR program for attainment pollutants through Regulation XVII – Prevention of Significant Deterioration (Regulation XVII), which will not be affected by the proposed amendments.

Proposed amendments for Rule 1304 – Exemptions (Rule 1304) and Rule 2005 are necessary to implement a narrow Best Available Control Technology (BACT) exemption. The exemption will allow for emission increases associated with air pollution control equipment installed or modified for regulatory compliance with a Best Available Retrofit Control Technology (BARCT) rule required to transition the REgional ~~Clean~~CLean Air Incentives Market (RECLAIM) program for oxides of nitrogen (NOx), to a command-and-control regulatory structure.

BACKGROUND

The South Coast AQMD Governing Board adopted the RECLAIM program on October 15, 1993 under Regulation XX – REgional ~~Clean~~CLean Air Incentives Market (RECLAIM) (Regulation XX). RECLAIM is a market-based emissions trading program designed to reduce NOx and oxides of sulfur (SOx) emissions through a market-based approach for facilities with NOx or SOx emissions greater than or equal to four tons per year. The program replaced a series of existing and future command-and-control rules and was designed to provide facilities with the flexibility to seek the most cost-effective solution to reduce their emissions.

The 2016 Air Quality Management Plan (AQMP) which was adopted on March 3, 2017 and includes control measure CMB-05: Further NOx Reductions from RECLAIM Assessment. Control measure CMB-05 committed to identify approaches to make the RECLAIM program more effective in ensuring equivalency with command-and-control regulations implementing BARCT and to provide an assessment of the RECLAIM program in order to achieve further NOx emission reductions of five tons per day. During the adoption of the 2016 AQMP, the Resolution directed staff to modify control measure CMB-05 to achieve five tons per day of NOx emission reductions as soon as feasible but no later than 2025, and to transition the RECLAIM program to a command-and-control regulatory structure requiring BARCT as soon as practicable.

In addition, on July 26, 2017, California State Assembly Bill 617 – Nonvehicular Air Pollution: Criteria Air Pollutants and Toxic Air Contaminants (AB 617) was approved by the Governor, which addresses nonvehicular air pollution (criteria pollutants and toxic air contaminants). RECLAIM facilities that are in the state's greenhouse gas cap-and-trade program are subject to the requirements of AB 617. Among the requirements is for air districts to develop, by January 1, 2019, an expedited schedule for the implementation of BARCT no later than December 31, 2023, with highest priority to those permitted units that have not modified emissions-related permit conditions for the greatest period of time. The schedule shall not apply to an emissions unit that has implemented BARCT due to a permit revision or a new permit issuance since 2007.

One of the rules needed for the RECLAIM transition, is Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR 1109.1) which is an industry-specific command-and-control landing rule and will establish NOx BARCT limits or facility-wide emission reductions that are equivalent to BARCT, while preventing carbon monoxide (CO) emissions from increasing, for combustion equipment located at petroleum refineries and facilities with related operations to petroleum refineries. PR 1109.1 will affect sixteen facilities, including nine petroleum refineries, three small refineries, and four facilities with related operations and establish NOx BARCT limits for nearly three hundred pieces of combustion equipment. During the development of PR 1109.1, a co-pollutant issue was identified where installation of Selective Catalytic Reduction (SCR) systems can trigger NSR, requiring operators to reduce the sulfur content in refinery fuel gas. SCR is a key NOx emission reduction technology to achieve low levels of NOx under PR 1109.1. Staff is proposing a narrow BACT exemption under Proposed Amended Rule 1304 (PAR 1304) and changes to the BACT applicability in Proposed Amended Rule 2005 (PAR 2005) to allow facilities under PR 1109.1 to focus on meeting NOx limits without concurrently addressing refinery fuel gas cleanup.

Co-Pollutant Emissions from Installation of Selective Catalytic Reduction Systems

Installations of SCR systems to control NOx emissions from a refinery boiler or heater can result in a relatively small increase in emissions of particulate matter (PM) from the SCR system as ammonia emissions. Ammonia emissions from new and modified SCR systems are subject to BACT under Regulation XIII, which limits ammonia emissions to 5 ppm. Emissions of PM from the refinery boiler or heater occur as a result of the ammonium sulfate formed from the sulfur in the refinery fuel gas and ammonia from the SCR system. If the PM emissions are greater than one pound per day, Regulation XIII would apply, triggering BACT, which currently would require a 30 ppm sulfur limit[1,2] in the refinery fuel gas.

There are five major petroleum refinery companies under PR 1109.1 representing seven refineries with separate South Coast AQMD Facility ID numbers. Of the seven refineries, two refineries have sulfur contents in their refinery fuel gas as low as 30 ppm or lower. The sulfur content in the refinery fuel gas for the other five refineries ranges between 40 to 179 ppm. It is possible that these

[1] The sulfur limit for refinery gas in Rule 431.1 – Sulfur Content of Gaseous Fuels is 40 ppm calculated as hydrogen sulfide (H_2S). However, RECLAIM facilities are currently exempt from Rule 431.1 and the sulfur content in refinery fuel gas varies between refineries from 27 to 179 ppm. Since the lowest sulfur limit currently achieved in practice for refinery fuel gas is 30 ppm, it represents BACT for the sulfur content in refinery fuels.

[2] 40 CFR Part 60 Subpart J – Standards of Performance for Petroleum Refineries and 40 CFR Part 60 Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 also specify possibly applicable sulfur emission limits for refinery fuel gas.

five refineries will have SCR projects where the increase in emissions of PM is greater than one pound per day, triggering BACT requirements under Regulation XIII. BACT for the sulfur content in refinery fuel gas would require a sulfur treatment system to achieve a sulfur level of 30 ppm, which could cost over $100 million to install.[3] Figure 1 below demonstrates the generation of emissions of PM with an aerodynamic diameter less than or equal to 10 microns (PM_{10}) as a result of an SCR installation utilized as a NOx control technology for a refinery heater.

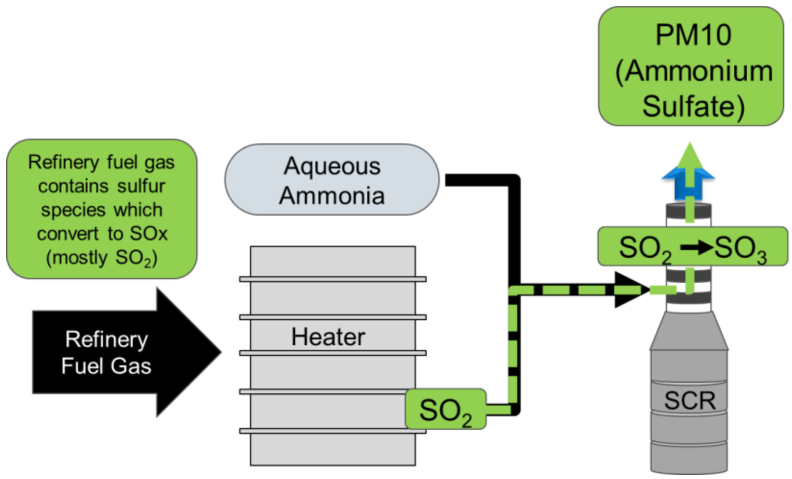

Figure 1-1. Schematic of Directly Emitted PM_{10} Emissions Due to SCR Installation on a Refinery Heater

SCR installations will substantially reduce NOx emissions but will also result in small increases in emissions of PM; potentially triggering the BACT requirement in Rule 1303 – Requirements (Rule 1303). It should be further noted that although there are increases in emissions of PM in the stack, the formation of PM in the ambient air is not expected to increase. Due to the presence of existing ammonia in the atmosphere, similar PM emissions would have occurred regardless.

In addition to increases in emissions of PM in the stack from modifying or installing SCR systems, there may be an NSR increase of SOx if a refinery replaces the basic equipment as part of the project. Although the replacement should expectedly result in a net emission reduction, assuming no increase in the cumulative total maximum rated capacity, with the removal of the older unit being replaced by a more efficient unit, projects that combine modifications or installations of SCR systems with basic equipment replacements will trigger BACT for PM_{10} and SOx under Regulation XIII and Rule 2005.

Under Regulation XIII, basic equipment replacements would trigger BACT because replacements are permitted as new units instead of modifications of existing sources. To determine the amount of offsets required and BACT applicability, new units use a zero baseline for the emission calculation.[4] There are provisions in Rule 1304 that allow a facility to use the emission reductions

[3] Staff will address refinery fuel sulfur content during the transition of SOx RECLAIM to a command-and-control regulatory structure.

[4] Rule 1306(d) is used to determine the amount of offsets required pursuant to Rule 1303(b)(2) and BACT applicability pursuant to Rule 1303(a).

from removing an older unit to offset the emissions for the replacement.[5] Although Regulation XIII has offset exemptions for replacements, all new units, including replacements, are still required to meet BACT.

When discussing the co-pollutant emissions from installation of SCR systems, due to the ammonia slip from the SCR, projects that only involve the installation or modification of an SCR system could result in an increase of PM_{10} emissions from the existing source. Projects that combine a unit replacement with installation or modification of an SCR system, could result in emission increases of both PM_{10} and SOx. Changes are needed in Regulation XIII and Rule 2005 to address the emission increase of PM_{10} when the project involves the installation or modification of an SCR for an existing unit, and for both PM_{10} and SOx emission increases if a unit replacement is combined with the SCR project.[6]

REGULATORY BACKGROUND FOR NEW SOURCE REVIEW

South Coast AQMD has two NSR programs for nonattainment pollutants: Rule 2005 – New Source Review for RECLAIM (Rule 2005) and Regulation XIII – New Source Review (Regulation XIII). Rule 2005 establishes NSR requirements for NOx and SOx emission increases at RECLAIM facilities. Regulation XIII establishes NSR requirements for emission increases of nonattainment criteria pollutants and their precursors, ammonia, and ozone depleting compounds at any facility. For RECLAIM facilities, Regulation XIII only applies to pollutants not specifically regulated by Regulation XX.[7] Both NSR programs are designed to implement state and federal NSR requirements and have been approved by California Air Resources Board (CARB) and United Sates Environmental Protection Agency (U.S. EPA) in 1996 for inclusion into the State Implementation Plan. Any changes or revisions to either NSR regulatory program will need to satisfy state and federal requirements that pertain to NSR. South Coast AQMD also has partial delegation to implement the PSD program for attainment pollutants through Regulation XVII.

Regulatory Background for Rule 1304

Regulation XIII establishes the federal and state mandated pre-construction review program for new, modified, or relocated sources within the jurisdiction of the South Coast AQMD, except for sources of NOx and SOx that are subject to Regulation XX. Regulation XIII currently consists of 13 rules, including Rule 1304 – Exemptions (Rule 1304). Rule 1304 includes exemptions for specific sources from the modeling requirement of Rule 1303 paragraph (b)(1) and the offsetting requirement of Rule 1303 paragraph (b)(2). Rule 1304 was adopted on October 5, 1979 and last amended on June 14, 1996.

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[5] Rule 1304(a)(1) specifies the offset exemption for replacements that are functionally identical to the source being replaced. Rule 1304(c)(2) specifies the offset exemption for facility modifications with emission reductions occurring concurrently with a new or modified source.

[6] Since basic equipment replacements are consider new units with a zero baseline BACT is triggered for all pollutants. The proposed BACT exemption is only for PM_{10} and SOx, BACT for CO, which is triggered under Regulation XVII, and BACT for ammonia would still be required.

[7] Emission increases of PM_{10} and SOx associated with SCR installations or modifications and basic equipment replacements at RECLAIM facilities would trigger BACT requirements for PM_{10} under Regulation XIII and BACT requirements for SOx under Rule 2005.

Regulatory Background for Rule 1325

Rule 1325 – Federal $PM_{2.5}$ New Source Review Program (Rule 1325) incorporates federal major NSR requirements for $PM_{2.5}$ into Regulation XIII. Rule 1325 applies to new Major Polluting Facilities of $PM_{2.5}$, Major Modifications to Major Polluting Facilities of $PM_{2.5}$, and any facility with an emission increase or potential to emit (PTE) of 70 tons per year or more of $PM_{2.5}$ or its precursors, which are NOx, SOx, VOC, and ammonia. Rule 1325 only applies to sources within the South Coast Air Basin (SOCAB), which is designated as nonattainment for $PM_{2.5}$. Rule 1325 was adopted on June 3, 2011 and last amended on January 4, 2019.

$PM_{2.5}$ is a sub-set of PM_{10} and is defined as airborne particulate matter with a nominal aerodynamic diameter of 2.5 micrometer or less, including gaseous emissions which condense to form $PM_{2.5}$ at ambient temperatures, and is measured in accordance with U.S. EPA Test Methods 201A and 202[8]. Since $PM_{2.5}$ is a sub-set of PM_{10}, new or modified sources could not emit $PM_{2.5}$ more than the Regulation XIII threshold values for PM_{10} without providing offsets and applying BACT, which is equivalent to federal Lowest Achievable Emissions Rate (LAER). Currently, BACT for PM_{10} is the same as BACT for $PM_{2.5}$. Rule 1325 regulates $PM_{2.5}$ as a non-attainment pollutant and all other provisions in Regulation XIII do not apply to $PM_{2.5}$, including the exemptions in Rule 1304 or eligibility for the Priority Reserve through Rule 1309.1 – Priority Reserve.

Rule 1325 mirrors the federal requirements specified in Title 40 of the Code of Federal Regulations (CFR) under Part 51 Section 165 (40 CFR 51.165), which include the definitions and procedures to determine if LAER is applicable to a major source or major modification, as well as the significant emission rate and offsetting ratio for $PM_{2.5}$. The provisions in Rule 1325 were drawn from the provisions found in the CFR and were slightly modified to harmonize with the existing provisions in Regulation XIII, the public notice requirements in Rule 212, and the offset ratio for NOx or SOx based on Regulation XIII or Rule 2005, as applicable. Rule 1325 incorporates the federal NSR thresholds for $PM_{2.5}$, which is 10 tons per year for Major Modifications at existing Major Stationary Sources of $PM_{2.5}$. Projects for a Major Stationary Source for PM_{10} and/or $PM_{2.5}$ with a PTE greater than or equal to 10 tons per year would trigger federal major NSR for $PM_{2.5}$ before exceeding the Major Modification threshold of 15 tons per year for PM_{10}. Since $PM_{2.5}$ is a subset of PM_{10}, an emission increase of PM_{10} would be evaluated according to the $PM_{2.5}$ threshold in Rule 1325, unless the fraction of $PM_{2.5}$ is quantified, since it is assumed that all the PM_{10} emissions are $PM_{2.5}$.

Rule 1325 subdivision (h) – Test Methods references the source testing methods that must be used if a source test is required. This reference to the source testing methods does not imply that source testing is required under Rule 1325. Language has been added clarifying that nothing in Rule 1325 affects the calculation methodology of Rule 1304 subparagraph (f)(1)(E).

Regulatory Background for Regulation XVII

Regulation XVII – Prevention of Significant Deterioration (Regulation XVII) was adopted on October 7, 1988 to implement the federal Prevention of Significant Deterioration (PSD) program.

[8] Rule 1325 subdivision (h)

Regulation XVII specifies the preconstruction review requirements for major stationary sources and major modifications that emit Attainment Air Contaminants.[9] An Attainment Air Contaminant is any air pollutant with a NAAQS that has been designated as attainment or unclassifiable by U.S. EPA, or is a pollutant regulated under the federal Clean Air Act and no applicable NAAQS exists.[10] South Coast AQMD is in attainment, except for the Coachella Valley, with the federal PM_{10} air quality standards; PM_{10} is designated as nonattainment with the state ambient air quality standards.

Regulatory Background for Rule 2005

Rule 2005 – New Source Review for RECLAIM (Rule 2005) sets forth the NSR requirements for new or modified equipment or processes at RECLAIM facilities. Rule 2005 only applies to NOx and SOx. RECLAIM NSR must be equivalent to the federal and state NSR requirements, and meets equivalency programmatically by requiring a source with an emission increase to: 1) be equipped with BACT, 2) conduct modeling to demonstrate that the emission increase will not be a significant increase in the air quality concentration of nitrogen dioxide (NO_2) if the facility's total emissions exceed its 1994 starting allocation plus non-tradable credits, and 3) hold sufficient RECLAIM Trading Credits (RTCs) to offset emission increases for one year prior to commencing operation and, for certain facilities, at the beginning of every compliance year thereafter. Rule 2005 was adopted as part of the RECLAIM program on October 15, 1993 and last amended on December 4, 2015.

State and Federal New Source Review Requirements

Federal Requirements

Federal NSR requirements are part of the NAAQS attainment strategy and vary based on the area's attainment designation for each regulated pollutant. Since the South Coast Air Basin (Basin) is designated as extreme nonattainment for federal ozone standards, the Basin is subject to the strictest federal NSR requirements for volatile organic compound (VOC) and NOx sources. Extreme nonattainment thresholds for defining a federal Major Stationary Source or a Major Modification are the lowest thresholds to ensure that new and modified sources do not interfere with the Basin's progress towards reaching attainment.

Federal Nonattainment Major NSR Applicability

Under federal NSR, a new Major Stationary Source[11] or a Major Modification[12] at an existing Major Stationary Source with an emission increase that exceeds the Significant Emissions Increase thresholds would trigger federal NSR, require LAER,[13] which is equivalent to BACT as required in Regulation XIII for Major Polluting Facilities, and require emission offsets. BACT is not required under federal NSR provided that an air pollution control project does not exceed the federal NSR thresholds using the federal NSR applicability test codified in Title 40 of the Code of Federal Regulations (CFR) under Part 51 Section 165 (40 CFR 51.165) and Part 52 Section 21 (40 CFR 52.21).

[9] Rule 1701 – General subdivision (b)
[10] Rule 1702 – Definitions subdivision (a)
[11] 40 CFR 51.165(a)(1)(iv)
[12] 40 CFR 51.165(a)(1)(v)
[13] California Health and Safety Code Section 40405 defines state BACT similar to federal LAER

Table 1-1. Federal Nonattainment NSR Major Stationary Source Thresholds for SOx, PM_{10}, and $PM_{2.5}$

Pollutant	Major Stationary Source PTE[14]	Major Modification Significant Emissions Increase
	Tons per Year	
SOx	70	40
PM_{10}	70	15
$PM_{2.5}$	70	10

State Requirements

Under the California Clean Air Act and codified in Division 26 of the California Health and Safety Code, each air district is to include in its attainment plan a New Source Review program designed to achieve no net increase in emissions of nonattainment pollutants or their precursors for all new or modified sources with emission increases that exceed particular thresholds. South Coast AQMD uses a one pound per day "no net increase" threshold. In addition, similar to federal requirements, new and modified stationary sources are required to meet BACT, where BACT in California Health and Safety Code Section 40405 is defined the same as federal LAER. State NSR applies to new or modified sources with any emission increase, as compared to the federal major NSR which only applies to Major Stationary Sources and Major Source Modifications.

Senate Bill 288 – Protect California Air Act of 2003 (SB 288)

In 2002, U.S. EPA revised several components of the federal NSR program (2002 NSR Reform), which included changes to the NSR applicability test for modified major sources. In response to concerns with the federal NSR changes, Senate Bill 288, "Protect California Air Act of 2003" was enacted. One SB 288 provision, codified under California Health and Safety Code Section 42504, states "*… No air quality management district or air pollution control district may amend or revise its new source review rules or regulations to be less stringent than those that existed on December 30, 2002*." Air districts can make NSR changes that are more stringent than existing provisions, but changes that are less stringent are only allowed under specific conditions. Some of the NSR changes allowed by SB 288 are:

- Replacement of a rule that has allowed exposure to toxics or a dangerous condition where the replacement will result in greater public health protection;
- Replacing a technically problematic rule;
- Amending a rule to relieve a business of substantial hardship, but the air district must offset any emission increases;
- Adopting a temporary rule to address an emergency; and

[14] Only the Coachella Valley is designated as nonattainment for PM_{10}. Reclassification by U.S. EPA is currently pending additional data.

- For areas that attain all national ambient air quality standards if the changes will not impair maintenance with those standards or impair progress toward attaining state ambient air quality standards.

However, the NSR rule changes allowed, by these specific circumstances listed above, may not exempt or reduce the obligation to meet BACT for a major source that existed on December 30, 2002. For a rule change that is less stringent, the air district's board must base its decision to approve the rule change on substantial evidence in the record. The air district then submits the rules to CARB. If an SB 288 challenge is raised, CARB must, after a public hearing, approve or deny the rule changes. Approval is based on confirmation that the specific conditions as listed above are met.

SB 288 Applicability

SB 288 requires no backsliding of South Coast AQMD's NSR provisions that existed as of December 30, 2002. In 2002, South Coast AQMD had two NSR programs: Regulation XIII for non-RECLAIM "pollutants" and Rule 2005 for NOx and SOx RECLAIM. The proposed amendments to PAR 1304 and PAR 2005 are necessary due to the transition of NOx RECLAIM to a command-and-control regulatory structure, which is requiring facilities to comply with NOx BARCT rules at the same time that they are transitioning out of the market-based program. Incorporating an exemption in PAR 1304 and changing the BACT applicability in PAR 2005 for PM_{10} and SOx emission increases associated with SCR installations or modifications and basic equipment replacements to comply with NOx BARCT standards will not be backsliding since the command-and-control landing rule provisions for RECLAIM facilities are more stringent than the requirements that existed in 2002. Under command-and-control operators must meet all NOx BARCT standards, which is not a mandatory requirement in RECLAIM. Under RECLAIM, operators have the choice to install air pollution controls or purchase RTCs. Without the proposed command-and-control requirements, where SCR is needed to meet a NOx BARCT standard, it is unlikely that the refineries would implement projects to meet that standard. Therefore, the BACT requirement would never in reality have been triggered by the installation of air pollution control equipment or replacement of equipment. Instead, refineries would most likely purchase RTCs over installing SCR, since it would require a sulfur treatment system to achieve a sulfur level of 30 ppm in refinery fuel gas, which could cost over $100 million to install.

CARB is supportive of the proposal to add an exemption for PM_{10} and SOx emission increases from the installation or modification of air pollution control equipment. Staff has discussed with CARB the concepts for the proposed BACT exemption and believes that amending Rule 1304 and Rule 2005 will not be an SB 288 issue. The BACT exemption for compliance with NOx BARCT is not a relaxation under SB 288, since the BACT exemption is for facilities transitioning out of RECLAIM to implement more stringent requirements under a command-and-control regulatory structure. The installation of new equipment with add-on air pollution controls under Rule 2005 would be unlikely without the proposed BACT exemption because purchasing RTCs is less costly than installing add-on air pollution control equipment.

BACT Exemptions for Regulatory Compliance from Other California Air Districts

Other California air districts have provisions that exempt emission increases associated with installations or modifications for regulatory compliance. The following California air districts have provisions that exempt sources from BACT when a source is complying with a regulatory requirement, such as a BARCT standard.

Bay Area Air Quality Management District (BAAQMD) Regulation 1

Section 1-115 (Exemption, Modification to Meet Emission Standards) exempts modifications to existing sources that are necessary to comply with an emission regulation from the BACT requirements of Section 2-2-301 (Best Available Control Technology Requirement) and the offsetting requirements of Section 2-2-302 (Offset Requirements, Precursor Organic Compounds and Nitrogen Oxides) and Section 2-2-303 (Offset Requirements, PM2.5, PM10 and Sulfur Dioxide).

BAAQMD Regulation 2 Rule 2

Section 2-2-102 (Exemption, Emissions from Operation of Abatement Devices and Techniques) exempts the emissions of secondary pollutants from the BACT requirements of Section 2-2-301 (Best Available Control Technology Requirement) that result from the use of an abatement device or emission reduction technique to comply with the BACT or BARCT requirements for control of another pollutant. Although the emissions of secondary pollutants are exempt from BACT, Reasonably Available Control Technology (RACT) for control of the secondary pollutants is still required.

San Joaquin Valley Air Pollution Control District (SJVAPCD) Rule 2201

SJVAPCD Rule 2201 has a BACT exemption for emission increases of all air pollutants at existing facilities that install or modify an emission control technique performed solely for the purpose of regulatory compliance, provided all of the following conditions are met:

- There is no increase in:
  - The physical or operational design of the existing facility, except for those changes to the design needed for the installation or modification of the emission control technique itself;
  - The permitted rating or permitted operating schedule of the permitted unit;
  - Emissions from the stationary source that will cause or contribute to any violation of a NAAQS, Prevention of Significant Deterioration increment, or Air Quality Related Value in Class I areas; and
- The project does not:
  - Result in an increase in permitted emissions or PTE of more than 25 tons per year of NOx, or 25 tons per year of VOC, or 15 tons per year of SOx, or 15 tons per year of PM_{10}, or 50 tons per year of CO; or
  - Constitute a federal Major Modification promulgated pursuant to Title I of the Federal Clean Air Act, including 40 CFR 51.165.

NEED FOR AMENDMENTS

Proposed amendments for Rule 1304 and Rule 2005 are necessary to implement a narrow BACT exemption to ensure NOx reductions can be achieved under PR 1109.1. The exemption will be allowed for PM_{10} caused by the installation or modification of air pollution control equipment and PM_{10} and SOx emission increases associated basic equipment replacements that are combined with the installation or modification of air pollution control equipment for regulatory compliance with a BARCT rule required to transition the NOx RECLAIM program to a command-and-control regulatory structure.

It is possible that installing SCR systems to achieve the PR 1109.1 NOx limits of 5 ppm for boilers and heaters will result in an increase in emissions of PM that is greater than one pound per day, triggering BACT under Regulation XIII, which would require a sulfur treatment system to achieve a sulfur level of 30 ppm in refinery fuel gas, which could cost over $100 million to install. The large cost to address relatively small PM_{10} emission increases would substantially increase the cost-effectiveness to achieve the PR 1109.1 NOx limits. Refinery fuel gas cleanup projects can reduce emissions of PM and SOx, however, since PR 1109.1 is a NOx rule the cost-effectiveness is based on the NOx reductions while the cost, if refinery fuel gas cleanup was required, would include the cost of the installation of SCR plus refinery fuel gas cleanup. A narrow provision to exempt refineries from PM_{10} and SOx BACT requirements for SCR projects is needed to ensure cost-effective NOx levels can be implemented under PR 1109.1. If refineries are not exempt from PM_{10} and SOx BACT requirements, then staff would need to look at a higher NOx concentration limit that is not based on SCR systems, and anticipated NOx reductions expected under PR 1109.1 would not come to fruition.

PR 1109.1 is designed to achieve significant NOx reductions which are needed to attain the NAAQS for ozone. Staff worked with the U.S. EPA and the CARB on a path forward to achieve the NOx emission reductions from PR 1109.1. This approach will require a change to South Coast AQMD's current NSR provisions. Staff is proposing to incorporate an exemption in Rule 1304 and to change the BACT applicability in Rule 2005 to allow SCR installations or modifications and equipment replacements needed to comply with a NOx BARCT rule without triggering BACT.

Regulation XIII currently has an offsetting exemption for regulatory compliance under Rule 1304 (c)(4), for sources that are installed or modified solely to comply with local, state, or federal air pollution regulations, provided there is no increase in the maximum rated capacity of the source. When sources are exempt from offsetting under Rule 1304, South Coast AQMD provides and tracks offsets from the District Offset Accounts for Federal NSR Equivalency or "Internal Bank" for nonattainment air contaminants according to Rule 1315 – Federal New Source Review Tracking System (Rule 1315)[15]. In addition to tracking for federal NSR equivalency, South Coast AQMD tracks emission increases to demonstrate compliance with the state NSR requirement of no net increase of actual emissions for certain permitted new or modified sources, which is based

[15] Rule 1315 subdivision (c)

on their PTE and the nonattainment classification of the area they are located.[16] To ensure that emission increases are fully offset as required by federal major NSR, the offsets withdrawn from the Internal Bank are for Major Stationary Sources and Major Modifications that are exempt under Rule 1304, but are still subject to the offsetting requirement under federal major NSR.[17,18] The emission increases that could use the proposed BACT exemption in Rule 1304 will not be allowed to constitute a Major Stationary Source or Major Modification and therefore will not be subject to the federal major NSR offsetting requirement. Offsets will not be required to demonstrate equivalency with federal NSR for the emission increases that could be exempt from the BACT requirement, since the BACT exemption will be limited to emission increases that do not trigger federal major NSR and therefore there will be no impact to the offset availability for the Internal Bank. Additionally, PM_{10} offsets for the accounting to demonstrate equivalency with federal major NSR are only required for emission increases of PM_{10} sources in Coachella Valley. Effective July 26, 2013, U.S. EPA designated the South Coast Air Basin (SOCAB) as being in attainment with the federal PM_{10} standard and therefore offsets for PM_{10} are not required. However, since the Coachella Valley has not been designated as in attainment for the PM_{10} NAAQS, South Coast AQMD tracks and reports PM_{10} offsets from SOCAB for informational purposes only.[19] Furthermore, some of the SOx emission increases exempt from BACT that are for facilities still under the RECLAIM program are required to be offset according to the RTC holding requirement in Rule 2005. In addition to the state and federal offsetting equivalency demonstration, Rule 1315 subdivision (g) – California Environmental Quality Act Backstop Provisions requires tracking of all increases and decreases in PTE for major and minor sources that were exempt from providing offset under Rule 1304 or received offsets pursuant to Rule 1309.1. The purpose of Rule 1315 subdivision (g) is to ensure the cumulative net emission increases in any given year remain below the emission increases that were analyzed in the California Environmental Quality Act (CEQA) document for Rule 1315. The cumulative net emission increases for each year must remain below the threshold in Rule 1315 Table B in order for the Executive Officer to be able to continue to issue permits pursuant to Rule 1304 or Rule 1309.1. The September 3, 2021 Governing Board Status Report on Regulation XIII demonstrated that the actual and projected cumulative net emission increase of each nonattainment air contaminant at major and minor sources remain below the thresholds in Rule 1315 Table B. Based on the average increases and decreases in PTE at major and minor sources from 2011 through 2019 and the calculated PM_{10} emission increases of 0.24 tons per day from sources that could potentially use the proposed BACT exemption in Rule 1304 and be exempt from offsetting for regulatory compliance under Rule 1304 paragraph (c)(4), the PM_{10} thresholds in Rule 1315 Table B are not expected to be exceeded. Appendix B – Rule 1315

[16] The amount of offsets that must be provided to demonstrate no net increase in emissions is based on the actual emissions from a new or modified source. However, the new or modified sources subject to the no net increase requirement is based on PTE of the source and the attainment classification where the source is located. For instance, California Health and Safety Code 40919(a)(2) specifies the requirements for areas classified as serious for air pollution, which applies to PM_{10}, and requires no net increase in actual PM_{10} emission for new or modified sources with a PTE greater than or equal to 15 tons per year. The no net increase requirement for NOx and VOC is specified in California Health and Safety Code 40920.5(b) and applies to any increase of actual emissions for all sources, regardless of their PTE.

[17] Rule 1315 Staff Report for the February 4, 2011 amendments

[18] 77 FR 31200

[19] Governing Board Status Report on Regulation XIII – New Source Review (September 3, 2021)

Subdivision (g) of this Staff Report provides additional information on the analysis estimating the potential increase in PM_{10} emissions and the projected impact on the thresholds in Rule 1315 Table B.

PUBLIC PROCESS

Development of proposed amendments to Rule 1304 and Rule 2005 is being conducted through a public process. South Coast AQMD held remote Working Group Meetings for the proposed rule amendments as part of the Regulation XIII Working Group Meetings on January 21, 2021, February 18, 2021, April 15, 2021, May 13, 2021, and June 16, 2021. The proposed amendments to Rules 1304 and 2005 were also discussed during the PR 1109.1 Working Group Meetings on July 17, 2020, August 12, 2020, February 4, 2021, March 4, 2021, May 27, 2021, and September 15, 2021. The working group includes representatives from affected facilities, business representatives, environmental groups, other agencies, consultants, and interested parties. The purpose of the Working Group Meetings is to discuss the proposed amendments and offer stakeholders the opportunity to provide input and raise concerns during the rule development process with the objective to build a consensus and resolve key issues. The proposed amendments were also presented to community members that were interested in better understanding the requirements and implementation of the proposed amended rules during a Study Session on September 10, 2021.

Additionally, a Public Workshop was held on September 1, 2021.

CHAPTER 2: SUMMARY OF PROPOSED AMENDMENTS

PROPOSED AMENDED RULE 2005

PROPOSED AMENDED RULE 1304

PROPOSED AMENDED RULE 2005

Currently, all new or modified sources at a RECLAIM facility with an emission increase of a RECLAIM pollutant are subject to BACT under Rule 2005 subparagraph (c)(1)(A). The proposed provision in PAR 2005 paragraph (c)(5) allows a RECLAIM facility, installing add-on air pollution control equipment to comply with a command-and-control NOx emission limit for a Regulation XI rule, to apply the BACT requirement for a SOx emission increase under Rule 1303 paragraph (a)(1) instead of BACT under Rule 2005 subparagraph (c)(1)(a). RECLAIM facilities electing to meet the BACT requirement under Rule 1303 can use the limited BACT exemption in PAR 1304 subdivision (f) if the new or modified source meets the criteria specified in PAR 1304 subparagraphs (f)(1)(A) through (E).

Although these are RECLAIM facilities, these new or modified sources are subject to a Regulation XI rule as part of transitioning the RECLAIM program to a command-and-control regulatory structure. Therefore, these new or modified sources may be regulated under the command-and-control BACT provision in Regulation XIII. Regulating these sources under Regulation XIII is necessary to allow the use of the limited BACT exemption in PAR 1304, since the PM_{10} and/or SOx emission increases from the new or modified sources are a result of a NOx rule in Regulation XI.

PROPOSED AMENDED RULE 1304

The proposed amendments to Rule 1304 are needed to ensure NOx reductions can be achieved under PR 1109.1. The objective of PAR 1304 is to add a BACT exemption for PM_{10} and SOx emission increases associated with SCR installations or modifications to achieve proposed NOx concentration limits in PR 1109.1. SCR installations to control NOx emissions from a refinery boiler or heater subject to the BARCT limits in PR 1109.1 can result in emissions of PM due to the ammonium sulfate formed from the unreacted ammonia in the SCR catalyst and the sulfur in the refinery fuel gas. Additionally, SCR installations or modifications combined with basic equipment replacements would result in an emission increase for SOx. Since an increase in emissions of PM and/or SOx would trigger BACT requirements, staff worked with CARB and U.S. EPA on a resolution to attain the substantial NOx reductions from implementing the required control strategies to comply with the proposed NOx BARCT requirements in PR 1109.1. Staff proposes to incorporate a BACT exemption in PAR 1304 to allow the installation or modification of an emission control technology, such as SCR, to comply with a NOx BARCT rule without requiring BACT.

The BACT exemption from SJVAPCD was used as an example when developing the proposed BACT exemption to add in PAR 1304. Staff is proposing a similar, but narrower, BACT exemption that was developed with input from CARB and U.S. EPA. The BACT exemption is limited to:

- Projects that comply with a rule that establishes a BARCT emission limit for NOx;
- RECLAIM or former RECLAIM facilities that are complying with a NOx BARCT emission limit that is part of the transition from NOx RECLAIM to command-and-control regulatory structure;

- PM_{10} and/or SOx emission increases; and
- Projects below the federal major NSR thresholds.

The proposed BACT exemption will not apply to:

- Ammonia emissions associated with SCR installations;
- Projects with an increase in total capacity or utilization (including hours and throughput); or
- Additional improvements or upgrades that are not required for BARCT compliance.

PAR 1304 Paragraph (f)(1)

The limited BACT exemption specified in PAR 1304 paragraph (f)(1) is only applicable to new or modified permit units with PM_{10} and/or SOx emission increases caused by the installation or modification and operation of add-on air pollution control equipment or associated with the replacement of basic equipment that is combined with the installation or modification of add-on air pollution control equipment, provided each requirement in PAR 1304 subparagraphs (f)(1)(A) through (E) is met. Projects for regulatory compliance with a NOx BARCT landing rule could result in emission increases of just PM_{10}, if the project only involves the installation or modification of an SCR for an existing unit, or both PM_{10} and SOx, if the SCR project also includes the replacement of the basic equipment. Projects for NOx BARCT compliance, that only involve replacement of existing units with new units without the installation or modification of add-on air pollution control equipment, such as SCR, would not qualify for the BACT exemption. Additionally, PAR 1304 paragraph (f)(1) is consistent with other current provisions in Rule 1304, and the exemption from the BACT requirement of Rule 1303 paragraph (a)(1) must be approved by the Executive Officer or designee, which would be determined at the time of permitting.

The BACT exemption is only for PM_{10} and SOx emission increases associated with the installation or modification and operation of add-on air pollution control equipment for compliance with command-and-control requirements at RECLAIM and former RECLAIM facilities to transition NOx RECLAIM. This BACT exemption will not be backsliding under SB 288 since the more stringent command-and-control landing rule provisions for RECLAIM facilities did not exist in 2002. The objective of the proposed narrow BACT exemption is to address the co-pollutant issue tied to the installation or modification of add-on air pollution controls and the replacement of equipment that is combined with an installation or modification of add-on air pollution control required to transition NOx RECLAIM and therefore cannot be extended to non-RECLAIM facilities as it would result in an SB 288 issue.

PAR 1304 Subparagraph (f)(1)(A)

PAR 1304 subparagraph (f)(1)(A) limits the BACT exemption to new or modified permit units being installed or modified at RECLAIM or former RECLAIM facilities to comply with a NOx BARCT rule to transition the NOx RECLAIM program to command-and-control regulatory structure. Qualifying projects undertaken to meet conditional NOx Concentration Limits and Alternative BARCT NOx Limits, such as concentration NOx limits for a B-Plan or B-Cap, for PR 1109.1 may use the limited BACT exemption. Conditional NOx Concentration Limits and Alternative BARCT NOx Limits are considered NOx BARCT emission limits specified in

PAR 1304 subparagraph (f)(1)(A). The NOx BARCT limits must have been initially established before December 31, 2023. The BACT exemption will not apply to future BARCT rules with new limits initiated after December 31, 2023. Although the cutoff date excludes using the BACT exemption for future BARCT rules, the BACT exemption would apply to NOx BARCT limits that are later revised if they were initially established before December 31, 2023. Additionally, projects with applications that were not deemed complete prior to the September 1, 2021 Public Workshop for PAR 1304 and that were needed to comply with a NOx BARCT standard established as part of the NOx RECLAIM transition qualify for the BACT exemption.

PAR 1304 Subparagraph (f)(1)(B)

The proposed provision under PAR 1304 subparagraph (f)(1)(B) limits the BACT exemption to projects that have no increase in the cumulative total maximum rated capacity. The maximum rated capacity is based on the allowable permitted heat input capacity of the permit unit(s). However, if a maximum rated capacity is not specified on a permit, then the maximum rated capacity is based on the physical design capacity or the capacity specified on the nameplate of a combustion unit. Replacement projects with a variable number of units being replaced would be allowed under PAR 1304 subparagraph (f)(1)(B) as long as the post-project cumulative total maximum rated capacity does not exceed the pre-project cumulative total maximum rated capacity for the existing unit(s). A single unit can be replaced with one or more units or multiple units can be replaced with one or more units, as long as there is no increase in the cumulative total maximum rated capacity of the existing unit(s) being replaced and the replacement(s) serve the same purpose. The criteria to require that a replacement serve the same purpose as the unit being replaced was developed according to the definition for a replacement unit under federal NSR.[20] Under federal NSR, to be considered a replacement, a unit must be reconstructed[21] or completely take the place of an existing unit, be identical to or functionally equivalent[22] to the replaced unit, not alter the basic design parameters[23] of the process unit being replaced, and be replacing a unit that is permanently removed, disabled, or barred from operation by an enforceable permit. Replacements that meet the criteria under federal NSR can be considered an existing emissions unit[24] for the purpose of determining federal major NSR applicability. NSR applicability for an existing emissions unit uses a Baseline Actual-to-Projected-Actual test where the baseline actual emissions are based on the pre-project emissions.[25]

The PAR 1304 BACT exemption can be used for situations where a unit will be replaced with a new unit from a different source category (e.g., a boiler for a turbine). If the new unit is installed

[20] 40 CFR 51.165(a)(1)(xxi) and 40 CFR 52.21(b)(33) defined replacement unit

[21] A reconstructed unit as defined in 40 CFR 60.15(b)

[22] 40 CFR 51.165(a)(1)(xliv) and 40 CFR 52.21(b)(56) define functionally equivalent component, which means a component that serves the same purpose as the replaced component. The definitions of functionally equivalent component and basic design parameters were vacated. However, even though these definitions were removed, they can still be used as guidance to define replacements. See 86 FR 37918 stating: "However, while not controlling, the EPA and stakeholders may continue to look to the vacated definitions from the ERP rule to guide their understanding of the definition of replacement unit."

[23] 40 CFR 51.165(h)(2) and 40 CFR 52.21(cc)(2) define basic design parameters

[24] 40 CFR 51.165(a)(1)(vii)(B) and 40 CFR 52.21(b)(7)(ii)

[25] 40 CFR 51.165(a)(2)(ii)(C) and 40 CFR 52.21(a)(2)(iv)(c)

to meet a NOx BARCT limit and serves the same purpose, then the BACT exemption will not be restricted to require that the new unit be of the same source category. Units from different source categories that might "serve the same purpose" would not have the same basic design parameters and therefore would not meet the federal definition for a replacement. A unit being replaced with a unit from a different source category would then be considered a new emissions unit rather than a replacement unit, which is an existing emissions unit under federal NSR, since the unit would not meet the federal definition for a replacement. For a new emissions unit, federal major NSR applicability is determined using a Baseline Actual-to-Potential test where the baseline emissions are zero. As compared to an existing unit, and replacements that meet the federal definition for replacement, may use the Baseline Actual-to-Projected-Actual test and the pre-project emissions as the baseline emissions. If the unit treated as a new unit qualifies as a major modification, then it would not be able to use the BACT exemption in PAR 1304.

Below are examples of SCR installations with different replacement scenarios. As shown in the examples, the cumulative total maximum rated capacity for a project is determined by adding the maximum rated capacity of each of the grouped units. In the examples provided, the replacements are associated with an SCR installation since the BACT exemption is only applicable to projects that involve add-on air pollution control equipment.

Table 2-1. Examples of Project Scenarios with SCR Installations and Equipment Replacements

<table>
<tr><th>Project Scenario</th><th>Pre-Project Unit(s)</th><th>Post-Project Unit(s)</th></tr>
<tr><td>SCR installation and replacement of a single existing unit with a new unit</td><td>Existing Unit = 100 MMBtu/hr</td><td>New Unit = 100 MMBtu/hr</td></tr>
<tr><td rowspan="2">SCR installation and replacement of one existing unit with two new units</td><td rowspan="2">Existing Unit = 100 MMBtu/hr</td><td>New Unit = 60 MMBtu/hr</td></tr>
<tr><td>New Unit = 40 MMBtu/hr</td></tr>
<tr><td rowspan="2">SCR installation and replacement of two existing units with a new unit</td><td>Existing Unit = 60 MMBtu/hr</td><td rowspan="2">New Unit = 100 MMBtu/hr</td></tr>
<tr><td>Existing Unit = 40 MMBtu/hr</td></tr>
<tr><td rowspan="4">SCR installation and replacement of four existing units with two new units</td><td>Existing Unit = 50 MMBtu/hr</td><td rowspan="2">New Unit = 75 MMBtu/hr</td></tr>
<tr><td>Existing Unit = 50 MMBtu/hr</td></tr>
<tr><td>Existing Unit = 50 MMBtu/hr</td><td rowspan="2">New Unit = 75 MMBtu/hr</td></tr>
<tr><td>Existing Unit = 50 MMBtu/hr</td></tr>
<tr><td rowspan="6">SCR installation and replacement of two existing units with three new units</td><td rowspan="3">Existing Unit = 75 MMBtu/hr</td><td rowspan="2">New Unit = 50 MMBtu/hr</td></tr>
<tr></tr>
<tr><td rowspan="2">New Unit = 50 MMBtu/hr</td></tr>
<tr><td rowspan="3">Existing Unit = 75 MMBtu/hr</td></tr>
<tr><td rowspan="2">New Unit = 50 MMBtu/hr</td></tr>
<tr></tr>
</table>

PAR 1304 subparagraph (f)(1)(B) also includes a provision to avoid extended delays during equipment replacement by limiting simultaneous operations of new or modified permit unit(s) with the equipment being replaced to a maximum of 90 days, which is consistent with the startup period allowed in division (d) of Rule 1313 – Permits to Operate.

PAR 1304 Subparagraph (f)(1)(C)

The proposed provision in PAR 1304 subparagraph (f)(1)(C) is to ensure there is no increase in the physical or operation design capacity for the entire facility, except for the changes needed for the new or modified permit unit(s) that meet the criteria of PAR 1304 subparagraph (f)(1)(B). This provision differs from PAR 1304 subparagraph (f)(1)(B) which specifies the criteria to ensure there is no increase in the cumulative total maximum rated capacity for the new or modified permitted unit(s). PAR 1304 subparagraph (f)(1)(C) also specifies that an increase in efficiency is not an increase in the physical and operational design capacity.

The BACT exemption is not applicable for facility expansions, modernization projects, upgrades, or improvements that are not for BARCT compliance. This provision is to ensure that the BACT exemption is not used for the facility to increase utilization or capacity, which may result in higher emissions. The BACT exemption is not intended for debottlenecking or shifting loads from existing units to new or modified units with add-on air pollution controls, which would result in both an increase in utilization and actual emissions above current allowable levels. Excluding projects that are not related to an air pollution control project for NOx BARCT compliance, such as those that are solely for facility modernization or expansion, is necessary to ensure that the limited BACT exemption would not be backsliding under SB 288.

PAR 1304 Subparagraph (f)(1)(D)

The proposed criteria in PAR 1304 subparagraph (f)(1)(D) requires that the emissions from new or modified permit unit do not cause an exceedance of any state or national ambient air quality standard. This provision is a safeguard to ensure that an emission increase associated with the new or modified permit unit will not result in a potential exceedance of any ambient air quality standard, as demonstrated with modeling as required in Rule 1303 paragraph (b)(1). Rule 1303 paragraph (b)(1) requires that an applicant substantiate with modeling that a source will not cause a violation, or make significantly worse an existing violation, of any state or national ambient air quality standard at any receptor location within the South Coast Air Quality Management District. Modeling for Rule 1303 paragraph (b)(1) is conducted according to Appendix A of Rule 1303, or other analysis approved by the Executive Officer or designee. Appendix A specifies that an applicant must show that a significant increase in air quality concentration will not occur at any receptor location by either providing an approved modeling analysis or using the Screening Analysis. The Screening Analysis compares the emissions from the source an applicant is applying for to the Allowable Emissions in Table A-1. If the emissions are less than the Allowable Emissions, then no further analysis is required. If the emissions are greater than the allowable emissions, a more detailed air quality modeling analysis is required. Furthermore, the modeling demonstration is not required for VOC or SOx.

PAR 1304 Subparagraph (f)(1)(E)

PAR 1304 subparagraph (f)(1)(E) specifies that the BACT exemption can only apply to new or modified permit units that are not part of a project that is subject to federal major NSR. New or modified permit units that constitute a federal Major Stationary Source or Major Modification will be subject to BACT. Federal NSR applicability will be determined according to the federal definitions for Major Stationary Source or Major Modification as defined in 40 CFR 51.165 and 40 CFR 52.21. The provisions for the federal NSR program codified in 40 CFR 51.165 are applicable to the nonattainment pollutants, while 40 CFR 52.21 are the federal Prevention of Significant Deterioration (PSD) provision for attainment/unclassifiable pollutants. Appendix A – Federal New Source Review of this Staff Report provides additional information and a general guideline to implement the federal major NSR applicability test, which is incorporated by reference in PAR 1304.

For the purpose of determining federal major NSR applicability, emissions of PM will be calculated using the methodology below. PAR 1304 includes a provision in subparagraph (f)(1)(E) to make express that it is permissible to use a mass balance engineering calculation to calculate the increase in emissions of PM when installing add-or air pollution control equipment with ammonia. A mass balance calculation may be used provided it employs the percent conversion of SO_2 to SO_3 found in the catalyst manufacturer specifications and uses the representative fuel gas sulfur content. U.S. EPA confirmed that this approach is acceptable for the purpose of NSR applicability.

Calculations for Estimating PM for NSR Applicability

PM Mass Flow Rate Calculation: Pounds per Day

The following calculation method will be used to determine if the federal major NSR threshold is exceeded prior to issuance of the permit to construct. Emissions of PM calculation will be in pounds per day and compared to the federal major NSR threshold in tons per year. The following steps are used to calculate mass flow rate:

1. Calculate molar flow rate of refinery fuel gas used
2. Calculate the moles of SO_2 formed based on the fuel gas sulfur composition. Assume 100% total sulfur (expressed as H_2S) in the fuel gas is converted to SO_2
3. Calculate conversion of SO_2 to SO_3 in moles – SO_2 to SO_3 oxidation rate (based on provided manufacturer specifications of catalyst from the facility)
4. Calculate production of ammonium sulfate from SO_3. Assume 100% SO_3 is converted to ammonium sulfate
5. Convert molar flow rate of ammonium sulfate to mass flow rate

Example PM Calculation Related to SCR Installation

Consider a new SCR to be installed on an existing heater with a maximum rated heat input of 875 MMBtu/hr. Assuming worst case, 5% SO_2 would be converted to SO_3. Again, assuming worst case, the total sulfur concentration in the refinery fuel gas is 179 ppmv and average higher heating value is 1,330 btu/scf. Therefore, assuming a 5% SO_2 to SO_3 conversion, PM_{10} as ammonium sulfate is calculated as follows:

$$\frac{179\ lbmol\ total\ S\ as\ H_2S}{1\times 10^6\ lbmol\ fuel\ gas}\times\frac{1\ lbmol\ SO_2}{1\ lbmol\ H_2S}\times\frac{1\ lbmol\ FG}{385.5\ scf\ FG}\times\frac{1\ scf\ FG}{1{,}330\ BTU}\times\frac{875\ \times 10^6\ BTU}{1\ hr}\times\frac{0.05\ lbmol\ SO_3}{1\ lbmol\ SO_2}=\frac{0.015\ lbmol\ SO_3}{hr}$$

$$\frac{0.015\ lbmol\ SO_3}{hr}\times\frac{1\ lbmol\ (NH_4)_2SO_4}{1\ lbmol\ SO_3}\times\frac{132\ lb\ (NH_4)_2SO_4}{1\ lbmol\ (NH_4)_2SO_4}=\frac{1.98\ lb\ (NH_4)_2SO_4}{hr}\ or\ \frac{47.52\ \ lb\ (NH_4)_2SO_4}{day}$$

Assuming continuous operations throughout the year, 47.5 pounds of ammonia sulfate per day equals 8.7 tons of PM_{10} per year.

For the purpose of determining federal major NSR applicability for emissions of PM, the methodology described above will be used in lieu of conducting a source test when a facility submits a permit application for an SCR installation or modification. South Coast AQMD Source

Test Method 5.2 – Determination of Particulate Matter Emissions from Stationary Sources Using Heated Probe and Filter Source Test introduces an SO_2 oxidation bias in the measured PM condensable (back half) portion due to the sulfur dioxide dissolved in the impinger water converting to sulfur trioxide and then to sulfuric acid. The PM reference method is designed to measure Particulate Matter as defined in Rule 102 - Definition of Terms. Since federal major NSR applicability is based on the PM exiting the stack rather than the PM that would form regionally, the emissions for PM may be calculated using a mass balance calculation. During the permitting process, staff will work with operators to establish the appropriate condition to be included in the permit to reflect the parameters used to calculate the increase in emissions of PM such as the SO_2 to SO_3 percent conversion as specified by the catalyst manufacturer and the fuel gas sulfur content that is representative of the actual sulfur content will be incorporated into the facility's permit as enforceable permit conditions.

Due to the variability in the sulfur content among sources, the representative sulfur content used in the equation to calculate the increase in emissions of PM should represent the upper limit of an averaged value over a certain period. This calculation will be used to satisfy federal NSR, which is based on a tons per year basis, as well as Regulation XIII, which is based on pounds per day basis. Compliance with the permit limits will need to be demonstrated on a pounds per day (30-day average), as well as a tons/year basis. Rule 1315 requires South Coast AQMD to demonstrate equivalency with federal NSR offset requirements for major sources that are exempt from offsets under Rule 1304, therefore compliance with the permit limits will need to be demonstrated on a pounds per day (30-day average), as well as a tons/year basis. The 30-day average may be higher than the annual average to accommodate short-term fluctuations in sulfur content of the refinery fuel gas.

Calculaions for Estimating Emissions of PM for NSR Applicability

To determine if the new or modified permit unit(s) exceed the PM threshold for federal major NSR applicability, calculated values as shown in the table below will be used. Emission factors derived from source test will not be utilized. Table 2-2 – Maximum Firing Rate at Federal PM_{10} Threshold below determines the maximum firing rate at the federal threshold varying by oxidation rate and sulfur content. The emissions of PM will depend on several variables:

- Size of the unit;
- SO_2 to SO_3 oxidation over the catalyst; and
- Sulfur Content of the fuel.

SCR catalyst SO_2 oxidation rates will vary by catalyst manufacturers; lowest is 0.5% and highest can be 5%.

Table 2-2. Maximum Firing Rate at Federal PM_{10} Threshold

SO_2 to SO_3 Oxidation Rate	Firing Rate (MMBTU/hr) at Varying Total Sulfur ppm Required to Exceed Federal PM_{10} threshold (10 Tons per Year)			
	40 ppm sulfur	110 ppm sulfur	150 ppm sulfur	179 ppm sulfur
0.5%	39,152	14,237	10,441	8,749
1.0%	19,576	7,119	5,220	4,375
1.5%	13,051	4,746	3,480	2,916
2.0%	9,788	3,559	2,610	2,187
2.5%	7,830	2,847	2,088	1,750
3.0%	6,525	2,373	1,740	1,458
3.5%	5,593	2,034	1,492	1,250
4.0%	4,894	1,780	1,305	1,094
4.5%	4,350	1,582	1,160	972
5.0%	3,915	1,424	1,044	875

PAR 1304 Paragraph (f)(2)

The purpose of PAR 1304 paragraph (f)(2) is to clarify that new or modified permit units that qualify for the BACT exemption specified in PAR 1304 paragraph (f)(1) are still subject to all other requirements of Regulation XIII, including but not limited to, permit conditions limiting monthly maximum emissions as required in Rule 1313 – Permits to Operate. Specifically, permits issued utilizing the narrow BACT exemption are still required to have permit conditions limiting monthly maximum emissions pursuant to Rule 1313 paragraph (g)(2).

Existing Permit Limits

Permits with existing limits will need to be evaluated on a case-by-case basis to determine how to account for the emission increases that are exempt from BACT. Current permit limits may not account for the emission increase and therefore require new permit limits that reflect the assumptions used to determine that a unit did not exceed the federal NSR thresholds or trigger other regulatory requirements such as sulfur content in refinery fuel gas and SO_2 to SO_3 conversion rates of the SCR.

CHAPTER 3: IMPACT ASSESSMENT

POTENTIALLY IMPACTED FACILITIES

The proposed amendments to Rule 1304 and Rule 2005 technically would apply to all facilities in the NOx RECLAIM program that transitioned or are in the process of transitioning to a command-and-control regulatory structure which meet the criteria for the BACT exemption for PM_{10} and SOx emission increases that result from the installation or modification of an emission control technique required to comply with South Coast AQMD command-and-control NOx BARCT standards. It is expected that only five of the seven refineries that have a sulfur content in their fuel gas would elect to meet the BACT requirement under Rule 1303 allowed by PAR 2005 and meet the criteria for the BACT exemption in PAR 1304 due to the installation of SCR systems to meet NOx concentration limits under PR 1109.1.

CALIFORNIA ENVIROMENTAL QUALITY ACT

Pursuant to the California Environmental Quality Act (CEQA) and South Coast AQMD's Certified Regulatory Program (Public Resources Code Section 21080.5 and CEQA Guidelines Section 15251(l); codified in South Coast AQMD Rule 110), the South Coast AQMD is lead agency for the proposed project, which is comprised of Proposed Rules 1109.1 and 429.1, Proposed Amended Rules 1304 and 2005, and Proposed Rescinded Rule 1109. CEQA Guidelines Section 15187 requires an environmental analysis to be performed when a public agency proposes to adopt a new rule or regulation requiring the installation of air pollution control equipment or establishing a performance standard, which is the case with the proposed project. The South Coast AQMD ~~is preparing~~ has prepared a Subsequent Environmental Assessment (SEA) for the proposed project, which is a substitute CEQA document pursuant to CEQA Guidelines Section 15252, prepared in lieu of a Subsequent Environmental Impact Report. –The SEA ~~will contain~~ contains the environmental analysis required by CEQA Guidelines Section 15187 and ~~will tier~~ tiers off of the December 2015 Final Program Environmental Assessment (PEA) for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM) (referred to as NOx RECLAIM) and the March 2017 Final Program Environmental Impact Report (EIR) for the 2016 Air Quality Management Plan as allowed by CEQA Guidelines Sections 15152, 15162, 15168 and 15385. The Draft SEA ~~will be~~ was released for a ~~45~~ 46-day public review and comment period to provide public agencies and the public an opportunity to obtain, review, and comment on the environmental analysis. ~~Comments made~~ The South Coast AQMD received six comment letters relative to the analysis in the Draft SEA and responses to the comments ~~will be~~ have been included in the Final SEA.

SOCIOECONOMIC ASSESSMENT

The proposed amendments to Rule 1304 and Rule 2005 are administrative in nature and do not impose additional costs on the affected facilities. As such, no adverse socioeconomic impacts are anticipated.

DRAFT FINDINGS UNDER CALIFORNIA HEALTH AND SAFETY CODE SECTION 40727

California Health & Safety Code Section 40727 requires that the Board make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the public hearing and in the staff report. The draft findings are as follows:

Necessity

PAR 1304 and PAR 2005 are necessary to implement a narrow BACT exemption for PM_{10} and SOx emission increases associated with a project to reduce air pollution that includes air pollution control equipment installed to comply with a NOx BARCT standard at a RECLAIM or former RECLAIM facility that is transitioning from the RECLAIM program to a command-and-control regulatory structure.

Authority

The South Coast AQMD obtains its authority to adopt, amend, or repeal rules and regulations from the California Health and Safety Code Sections 39002, 40000, 40001, 40440, 40441, 40702, and 41508; and the Federal Clean Air Act.

Clarity

PAR 1304 and PAR 2005 have been written or displayed so that its meaning can be easily understood by the persons affected by the rule.

Consistency

PAR 1304 and PAR 2005 are in harmony with, and not in conflict with or contradictory to, existing federal or state statutes, court decisions or federal regulations.

Non-Duplication

PAR 1304 and PAR 2005 do not impose the same requirement as any existing state or federal regulation and is necessary and proper to execute the powers and duties granted to, and imposed upon the South Coast AQMD.

Reference

In amending Rule 1304 and Rule 2005, the following statutes which the South Coast AQMD hereby implements, interprets or makes specific are referenced: California Health and Safety Code Sections 39002, 40001, 40440, 40506, 40702, and 42300; and the Federal Clean Air Act Sections 172(c)(5) and 173.

COMPARATIVE ANALYSIS

In order to determine compliance with California Health and Safety Code Section 40727, Section 40727.2 requires a comparative analysis of the proposed amended rules with any Federal or District rules and regulations applicable to the same source. California Health and Safety Code Section 40727.2 (g) is not applicable because PAR 1304 and PAR 2005 do not impose a new or more stringent emission limit or standard, or other air pollution control monitoring, reporting or recordkeeping requirements. As a result, a comparative analysis is not required.

Appendix A – FEDERAL NEW SOURCE REVIEW

INTRODUCTION

The purpose of this Appendix is to provide general guidance for implementing the federal major New Source Review (NSR) provisions codified in Title 40 of the Code of Federal Regulations (CFR) under Part 51 Section 165 (40 CFR 51.165) and Part 52 Section 21 (40 CFR 52.21). The proposed BACT exemption under PAR 1304 subdivision (f) is only applicable to new or modified permit units that are not part of a project subject to federal major NSR. New or modified permit units subject to federal major NSR will not be allowed to use the BACT exemption in PAR 1304. To determine federal major NSR applicability for a proposed project, the federal definitions and calculation procedures specified in 40 CFR 51.165 and 40 CFR 52.21 will be used.

BACKGROUND

NSR is a preconstruction permitting program established under the Clean Air Act (CAA), which requires new Major Stationary Sources and Major Modifications of existing Major Stationary Sources to obtain a federal major NSR permit prior to beginning construction. The federal major NSR program comprises the nonattainment NSR program for sources in areas exceeding the National Ambient Air Quality Standards (NAAQS), and the Prevention of Significant Deterioration (PSD) program for sources in attainment or unclassifiable areas. These provisions are codified in 40 CFR 51.165 and 40 CFR 52.21, respectively. The nonattainment NSR program applies to nonattainment pollutants and their precursors, which for South Coast AQMD are NOx, VOC, $PM_{2.5}$, SOx, and NH_3. The federal NSR provisions codified in 40 CFR 52.21 apply to all other pollutants regulated under the PSD program,[26] which for South Coast AQMD includes, but is not limited to, CO and PM_{10}. Sources in nonattainment areas that will emit a nonattainment pollutant above a specific NSR threshold are required to offset the emission increase and meet Lowest Achievable Emission Rate (LAER), while sources in an attainment or unclassifiable area subject to PSD must meet federal Best Available Control Technology (BACT).[27]

APPLICABILITY OF FEDERAL NEW SOURCE REVIEW

To determine if a new or modified permit unit is not a federal major NSR event, and therefore eligible for the Rule 1304 BACT exemption, the definitions and applicable provisions in 40 CFR 51.165 and 40 CFR 52.21 shall be used. Under federal major NSR, a source is subject to federal NSR requirements if the emission increase associated with an NSR event exceeds the applicable federal NSR threshold. The applicable NSR threshold and calculation method used depends on whether the NSR event is for a new Major Stationary Source or a Major Modification of an existing Major Stationary Source.

Major Stationary Source

The first step in determining if an NSR event is subject to federal major NSR requirements is to determine if the facility or project is a Major Stationary Source under the applicable federal major NSR program. Federal major NSR defines a Major Stationary Source as any source that emits, or has the potential to emit (PTE), any regulated NSR air pollutant at or above a specified threshold,

[26] PSD also applies to other regulated NSR pollutants, such as, but not limited to, lead, sulfuric acid, H_2S, and fluorides.

[27] Sources are subject to other NSR requirements depending on the applicable federal NSR program.

which is dependent on whether a source is subject to the nonattainment NSR program or the PSD program.

Major Stationary Source Thresholds for South Coast AQMD Sources

A source in South Coast AQMD is subject to major NSR requirements if its PTE equals or exceeds a threshold for a Major Stationary Source listed in Table A-1 below. Major Stationary Source[28] as defined under federal major NSR means the same as a Major Polluting Facility as is defined in Regulation XIII.[29]

Table A-1. Federal NSR Major Stationary Source Thresholds for SOx, PM_{10}, and $PM_{2.5}$

Pollutant	South Coast AQMD Federal Attainment Status	Major Stationary Source PTE Thresholds (tons per year)
SOx	Nonattainment ($PM_{2.5}$ Precursor)	70
PM_{10}	Nonattainment[30]	70
$PM_{2.5}$	Serious Nonattainment	70

An NSR event for a new facility or project with a PTE less than the Major Stationary Source thresholds is not subject to federal major NSR. However, if a NSR event is a modification to an existing Major Stationary Source, then a multi-step process is used to determine whether it is a Major Modification subject to federal major NSR requirements. Additionally, a project at a minor source (i.e., a facility with a PTE below the Major Stationary Source thresholds) that by itself results in an emission increase equal to or greater than a Major Stationary Source threshold would be considered a Major Stationary Source for that pollutant for nonattainment NSR.[31]

Major Modification

Under federal major NSR, a project is considered to be a Major Modification and subject to federal NSR requirements only if the project meets all of the criteria listed below. A project must meet all criteria to be a Major Modification. If any one of the criteria is not applicable, then the project will not trigger federal major NSR. A project is considered a Major Modification if it is:

1. At an existing Major Stationary Source, and
2. Will result in a Significant Emissions Increase, and
3. Will result in a Significant Net Emissions Increase in the source’s emissions taking into account other contemporaneous increases and decreases at the facility.

[28] 40 CFR 51.165(a)(1)(iv)(A) and 40 CFR 52.21(b)(1)(i)
[29] Rule 1302 subdivision (s)
[30] Only the Coachella Valley is designated as nonattainment for PM10. Reclassification by U.S. EPA is currently pending additional data.
[31] 40 CFR 51.165(a)(1)(iv)(A)(3) and 40 CFR 52.21(b)(1)(i)(c)

Step 2 – Significant Emissions Increase Test

To determine if an NSR event is a Major Modification a multi-step applicability test is used to determine if the emissions from a project at an existing Major Polluting Facility will result in a Significant Emissions Increase. A project[32,33] is defined by U.S. EPA as "a physical change in, or change in the method of operation of, an existing major stationary source" and include the emission increases for all new, modified, and debottlenecked units, as well as fugitive emissions. The emission increases of each individual emission source related to the project must be added together to determine if the permitting project, as a whole, results in a Significant Emissions Increase. The federal NSR major applicability test is complete if a permitting action does not result in a Significant Emissions Increase. If a project does not trigger federal major NSR under Step 2, then the netting calculation under Step 3 is not necessary. If there is a Significant Emissions Increase associated with a project, Step 3 is used to determine if there is also a Significant Net Emission Increase depending on whether the emission increase is for an ozone or non-ozone precursor.

Table A-2. Federal NSR Significant Emissions Increase Thresholds for SOx, PM_{10}, and $PM_{2.5}$

Pollutant	Significant Emissions Increase (tons per year)
SOx	40
PM_{10}	15
$PM_{2.5}$	10

The multi-step process to determine if a project is a Major Modification subject to federal major NSR is summarized in Figure A-1 below. As described above, the Major Modification applicability test ends if a project does not trigger an individual step and only proceeds to the next step if a project triggers the prior step.[34]

32 40 CFR 51.165(a)(1)(xxxix) and 40 CFR 52.21(b)(52)

33 The federal definition for a project is any change to a Major Stationary Source, whereas a Major Modification is a change to a Major Stationary Source that would result in a Significant Emissions Increase and a Significant Net Emissions Increase. The federal major NSR applicability provisions use the term project to determine if a change to a Major Stationary Source is a Major Modification that would be subject to NSR requirements.

34 Federal major NSR provisions and guidance refer to the Significant Emissions Increase Test as Step 1 and the Significant Net Emissions Increase Test as Step 2 of the NSR applicability Test for Major Modifications. Additionally, on November 24, 2020, U.S. EPA promulgated a final rule (85 FR 74890) on "project emissions accounting" that was asserted to "clarify" that both increases and decreases from a proposed project can be considered in Step 1 of federal NSR tests. The project emissions accounting rule did not require changes or otherwise affect South Coast AQMD's State Implementation Plan rules already approved under 40 CFR 51.165 (see 85 FR 74904). U.S. EPA also expressly disclaimed that the provisions extended to nonattainment NSR as it applies to ozone precursors in extreme areas under Clean Air Act section 182(e)(2) (see footnote n. 3 in 85 FR 74891). On October 18, 2021, U.S. EPA published notice (86 FR 57585) that it denied a petition for reconsideration of the project emissions accounting rule. U.S. EPA stated, however, that it "plans to initiate, at its own discretion, a rulemaking process to consider revisions to the NSR regulations." This staff report discusses the federal NSR test in terms of conventional two-step applicability without emphasis on the accounting considerations deemed permissible by the project emission accounting rule, but those provisions of the federal test, to the extent they continue to be in force, may present additional options to demonstrate a project is not a federal "major modification" under PAR 1304(f)(1)(E), as needed to be approved for the limited BACT exemption.

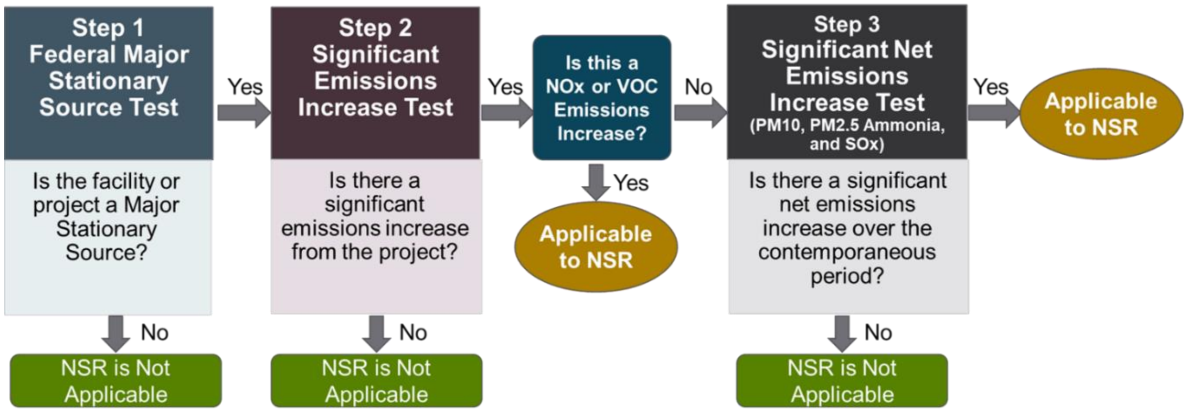

Figure A-1. Federal NSR Major Modification Applicability Test

Emissions Calculations Procedures

The calculations procedures specified in 40 CFR 51.165(a)(2) and 40 CFR 52.21(a)(2), as summarized below, are used to determine if a proposed project will result in a Major Modification. The calculations are performed for each pollutant separately. Different pollutants or precursors are not summed together to determine NSR applicability. As mentioned above, a project is a Major Modification if there is both a Significant Emissions Increase (Step 2) *and* a Significant Net Emissions Increase (Step 3). If a project does not result in a Significant Emission Increase, then it is not a Major Modification. If the project does result in a Significant Emission Increase, then the project is a Major Modification only if it also results in a Significant Net Emission Increase. Depending on the type of emission unit being proposed for a project (i.e. a new or existing emissions unit), the following procedures are used to calculate if a project will result in a Significant Emission Increase:

Actual-to-Projected-Actual Applicability Test for Projects that Only Involve Existing Emissions Units[35]

Federal major NSR defines an existing emissions unit[36] as a unit that has existed for more than 2 years since the unit began operation. For an existing emissions unit, an Actual-to-Projected-Actual test is used to determine if an emission increase is significant. The Actual-to-Projected-Actual test for an existing emissions unit compares the baseline actual emissions before the proposed project (Baseline Actual Emissions, BAE) and the future actual emissions after the proposed project (Projected Actual Emissions, PAE). A Significant Emissions Increase of a regulated NSR pollutant is projected to occur if the difference between the Projected Actual Emissions and the Baseline Actual Emissions, for each existing emissions unit, equals or exceeds the Significant Emissions Increase threshold for that pollutant (Table A-2).

The Actual-to-Projected-Actual applicability test calculates an emission increase for an existing emissions unit as:

$$\textbf{Emissions Increase} = \textbf{PAE}_{\textbf{After the project}} - \textbf{BAE}_{\textbf{Before the project}}$$

[35] 40 CFR 51.165(a)(2)(ii)(C) and 40 CFR 52.21(a)(2)(iv)(c)
[36] 40 CFR 51.165(a)(1)(vii)(B) and 40 CFR 52.21(b)(7)(ii)

A source may elect to use the PTE for the emissions unit in lieu of projected actual emissions as provided by 40 CFR 52.21(b)(41)(ii)(d).

Under federal major NSR, for a replacement unit, the baseline emissions are the actual emissions of the existing unit being replaced rather than a zero baseline if considered a new unit, which is different than Regulation XIII where a zero baseline for new and replacement units is used. When defining an existing emission unit in 40 CFR 51.165(a)(1)(vii)(B) and 40 CFR 52.21(b)(7)(ii), federal major NSR provisions specify that a replacement unit is an existing emissions unit. Therefore, under federal major NSR, a replacement unit that meets the definition in 40 CFR 51.165(a)(xxi) and 40 CFR 52.21(b)(33) would be considered an existing emissions unit, not a new emissions unit, and the Actual-to-Projected-Actual NSR applicability test with baseline emissions before a project, which are the baseline actual emissions of the existing unit being replaced, may be used.

Projected Actual Emissions[37]

Federal major NSR defines Projected Actual Emissions as the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any 12-month period within 5 years following the date the unit resumes regular operation after a proposed project, or any 12-month period within 10 years of when a unit resumes regular operation after a proposed project that involves increasing the emissions unit's design capacity or PTE, if the full utilization of the unit would result in a Significant Emissions Increase or a Significant Net Emissions Increase. When determining the Project Actual Emissions, a source must consider all relevant information, including but not limited to, historical operational data and the company's own business forecast. Projected Actual Emissions shall also include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions, but can exclude emission increases associated with the company's demand growth.

Demand Growth Exclusion[38]

Projected Actual Emissions allows for a Demand Growth exclusion. The Demand Growth exclusion removes emission increases associated with the facility's output that would have occurred regardless of the project. The Demand Growth exclusion is allowed for emissions that an existing source could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions, including any increased utilization due to product demand growth, if the emissions are unrelated to the project. A facility must justify and substantiate the Demand Growth exclusion with historical operation data demonstrating that a source achieved certain emission levels for the specified period.

Baseline Actual Emissions[39]

For an existing emission unit, the Baseline Actual Emissions are the actual emissions emitted, in tons per year, during any consecutive 24-month period during the last 10 years if the emission unit is at a facility other than Electricity Generating Facility (EGF), or the last 5 years if the emission unit is at an EGF. The Baseline Actual Emissions must be based on the same consecutive 24-

[37] 40 CFR 51.165(a)(1)(xxviii) and 40 CFR 52.21(b)(41)
[38] 40 CFR 51.165(a)(1)(xxviii)(B)(3) and 40 CFR 52.21(b)(41)(ii)(c)
[39] 40 CFR 51.165(a)(1)(xxxv) and 40 CFR 52.21(b)(48)

month period for a pollutant, but a different 24-month period can be used for each pollutant. All emissions from a stationary source for each project, including fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions must be included in the Baseline Actual Emissions. Any exceedances that were in violation of permit or regulatory emissions limits must be excluded from the Baseline Actual Emissions. Additionally, non-EGF emission units, must adjust the Baseline Actual Emissions to exclude emissions that would exceed an emission limit under a current regulation for the chosen 24-month period, unless the emission limit is part of a Maximum Achievable Control Technology standard and credit for the reductions have not been claimed for State Implementation Plan purposes.

Actual-to-Potential Test for Projects that Only Involve Construction of a New Emissions Unit(s)[40]

A new emissions unit is any emissions unit which is, or will be, newly constructed and which has existed for less than 2 years from the date the emission unit first operated.[41] For a new emissions unit, an Actual-to-Potential test is used to determine if an emission increase is significant. A Significant Emissions Increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the PTE from each new emissions unit following completion of the project and the baseline actual emissions[42] of these units before the project equals or exceeds the significant amount for that pollutant (Table A-2).

The Actual-to-PTE applicability test calculates an emission increase for a new emission units as:

$$\boldsymbol{Emissions\ Increase = PTE_{After\ the\ project} - BAE_{Before\ the\ project}}$$

“For a new emissions unit, the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit's potential to emit”; therefore the Actual-to-PTE applicability test for a new emission units can be interpreted as a PTE-to-PTE test:

$$\boldsymbol{Emissions\ Increase = PTE_{After\ the\ project} - PTE_{Before\ the\ project}}$$

Hybrid Test for Projects that Involve Multiple Types of Emissions Units[43]

A Significant Emissions Increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the Actual-to-Projected-Actual Applicability Test or the Actual-to-Potential Test, as applicable, with respect to each emissions unit, equals or exceeds the significant amount for that pollutant.

The process to calculate whether a Significant Net Emissions Increase (Step 3) will occur at an existing Major Stationary Source is specified under the definition of Net Emissions Increase contained in 40 CFR 51.165(a)(1)(vi) and 40 CFR 52.21(b)(3).

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[40] 40 CFR 51.165(a)(2)(ii)(D) and 40 CFR 52.21(a)(2)(iv)(d)
[41] 40 CFR 51.165(a)(1)(vii)(A) and 40 CFR 52.21(b)(7)(i)
[42] 40 CFR 51.165(a)(1)(xxxv)(C) and 40 CFR 52.21(b)(48)(iii)
[43] 40 CFR 51.165(a)(2)(ii)(F) and 40 CFR 52.21(a)(2)(iv)(f)

Step 3 – Significant Net Emissions Increase Test

Projects with emission increases of non-ozone precursors at an existing Major Stationary Source (Step 1) with a Significant Emissions Increase (Step 2) are required to determine if there is a Significant Net Emissions Increase (Step 3). Step 3 is only applicable for projects with PM_{10}, $PM_{2.5}$, ammonia, and SOx increases. If Net Emissions are greater than or equal to the Significant Emissions Threshold, then the project would be a Major Modification subject to federal major NSR requirements.[44] Projects with emission increases of PM_{10}, $PM_{2.5}$, ammonia, and SOx can net out of being a Major Modification if the Net Emission increase is less than the Significant Emissions Threshold (Table A-2).

Netting Methodology

Net Emissions is the sum of the project emissions and the sum of the emission increases and decreases at the facility during the contemporaneous period for the proposed project.

$$Net\ Emissions = Project\ Emissions\ +\ Contemporaneous\ Project\ Emission$$

Contemporaneous Project Emissions

The Contemporaneous Period includes a look back and a look forward period. The look back period begins five years before the date of construction of the (current) project commences. The look forward period begins from the date of construction of the (current) project to the date that the increase from the (current) project occurs. For a replacement unit that requires shakedown, this may include a reasonable shakedown period, but may not exceed 180 days.

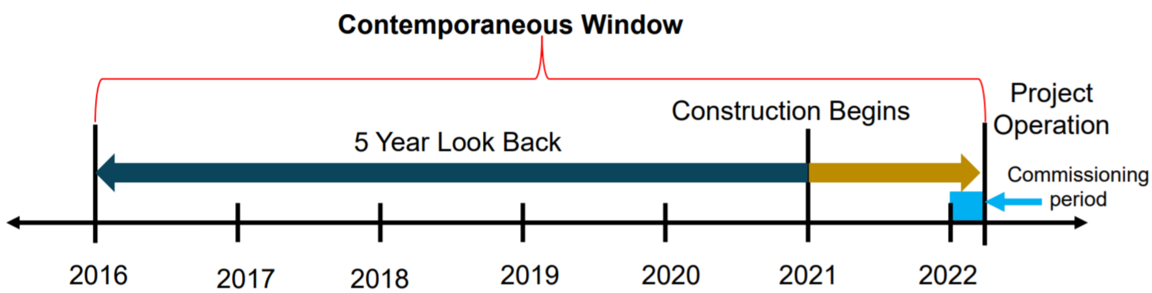

Figure A-2. Example of The Contemporaneous Period for a Proposed Project

The calculation for Contemporaneous Project Emissions is dependent on when the emission unit within a project began operation.

$$\begin{matrix} Contemporaneous\ Project\ Emissions \\ (< 24\ Months) \end{matrix} = \begin{matrix} PTE \\ (post\ modification) \end{matrix} - \begin{matrix} PTE \\ (pre\ modification) \end{matrix}$$

$$\begin{matrix} Contemporaneous\ Project\ Emissions \\ (\geq 24\ Months) \end{matrix} = \begin{matrix} PTE \\ (post\ modification) \end{matrix} - \begin{matrix} Baseline\ Actual \\ Emissions \end{matrix}$$

[44] If a project results in a Significant Emissions Increase, a source can deem the project a Major Modification without needing to perform the netting analysis to determine if there will be a Significant Net Emissions Increase.

Creditable Increases and Decreases

For increases and decreases to be creditable, they must not have been relied on in an air quality analysis in a previous NSR permit analysis, or a "Reasonable Further Progress" demonstration for nonattainment pollutant ($PM_{2.5}$). A creditable decrease is based on Actual Emissions-to-PTE. If actual emissions are higher than existing allowable emissions, then the creditable decrease is based on the existing allowable emissions and the revised allowable emissions. Additionally, decreases must be enforceable by the date of construction commencement. A creditable increase must involve some amount of actual increase and must involve "approximately the same quantitative significance for public health and welfare" as the project emission increase.

Additional Considerations

Fugitive Emissions and Mobile Sources

Federal NSR and Regulation XIII differ in what emission sources are included to calculate facility emissions. The two areas where Federal NSR and Regulation XIII differ are consideration of fugitive emission and definition of mobile sources. Regulation XIII requires all facilities to include fugitive emissions, whereas fugitive emissions under federal NSR are only required if the source is one of the 28 listed source categories.

When calculating a facility's PTE to determine whether the facility is a Major Stationary Source, under federal major NSR, fugitive emissions, which are defined as those emissions that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening,[45] are included only if the facility is listed under one of the 28 source categories. If the facility is not included in the 28 source categories, then when determining if a source is a Major Stationary Source, fugitive emissions are not included in the facility's PTE.[46] For facilities considered a Major Stationary Source, fugitive emissions are included in the analysis to determine if a project results in a Significant Emissions Increase (Step 2) or a Significant Net Emissions Increase (Step 3).

For mobile sources, South Coast AQMD BACT guidelines require that the following sources be considered as part of the facility: in-plant vehicles, ship emissions during loading and unloading, and non-propulsion emissions within South Coast AQMD jurisdiction. Whereas the federal definition for Major Stationary Source which does not include the following when determining the PTE for a source: internal combustion engines for transportation purposes nor nonroad engines or vehicles.

Debottlenecking

When determining NSR applicability, the scope of a project must be clearly defined, and the emission increases from all affected emissions units must be accounted for. A project, which federally is defined as any physical change or change in the method of operation, can affect more than one emission unit, including bottlenecked units. Emission units with different operating capacities may constrain other emission units, resulting in a bottleneck that limits the production capacity of a process. Changes to the emission unit causing the constraint, either upstream or downstream from a bottleneck, which may result in increased emissions for a process, would be

[45] 40 CFR 51.165(a)(1)(ix) and 40 CFR 52.21(b)(20)
[46] 40 CFR 51.165(a)(1)(iv)(C) and 40 CFR 52.21(b)(1)(iii)

debottlenecking. For instance, a proposed project to increase the output rating of an upstream unit may result in the bottlenecked unit being able to accept a greater input from the modified upstream unit. Another example is if a proposed project to increase the operating capacity of a downstream unit could result in the bottlenecked unit being able to provide more output to the modified downstream unit after the change. Calculating emission increases must include both increases for all new or modified emission units as well as any other increases from other existing units not being modified that experience emission increases as a result of the change. Federal NSR provisions do not define debottlenecked unit, but the intent is that a debottlenecked unit is any unchanged unit at a source that increases its utilization following a change elsewhere at the source. Even when an emission unit is not going through a physical change or change in operation itself, any emission increase as a result of a project must be included for the purpose of NSR applicability.[47]

Emission increases from a debottlenecked unit as a result of a project must be included in the emissions calculation to determine NSR applicability. As discussed above, the emission increase for a new source is based on the source's PTE (Actual-to-PTE, with actual emissions having a zero emissions baseline), while the emission increase for existing units can be determine using the Actual-to-Projected Actual Applicability Test. For existing units, the Actual-to-Projected Actual Applicability Test must include the increases from the existing unit(s) being modified as well as the increases for other existing units not being modified but are being debottlenecked or increase their utilization as a result of the project.

If NSR is triggered, BACT or LAER is not required for the unchanged sources that had an increase in emissions as a result of the proposed project, BACT or LAER would only be required for the emissions units undergoing a change. The emission increases from both the changed and unchanged emissions units are used in air quality analysis.

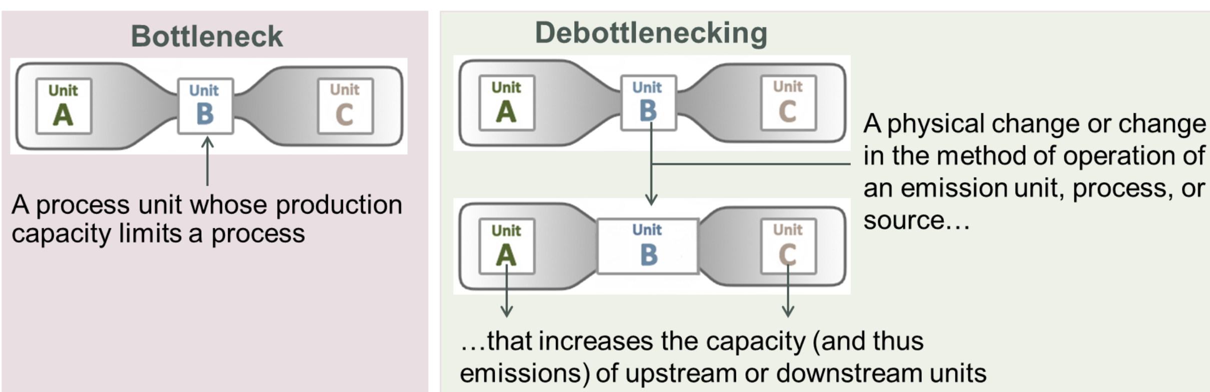

Figure A-3. Schematic of a Debottlenecked Unit

Project Aggregation

The purpose of the Significant Emissions Increase Test (Step 2) is to determine if a project will have an increase in emissions greater than or equal to the Significant Emissions Increase thresholds

[47] 71 FR 54235

for a Major Modification. As mentioned above, federal major NSR provisions define a "project" as a physical change in or change in the method of operation of an existing Major Stationary Source. Under the Significant Emissions Increase Test, when multiple emission units at an existing Major Stationary Source are changed, which would include any new, modified, or debottlenecked emission units, the emissions increase of each emission unit associated with the project must be added together when determining if the project as a whole is a Major Modification subject to federal major NSR requirements. The requirement to sum the emission increases from all substantially related emission units for a project during the Significant Emissions Increase Test is referred to as project aggregation. Project aggregation is to ensure that nominally-separate projects at a facility are treated as a single project if they are substantially related. Projects are considered substantially related, and thus aggregated, when they have a technical or economic dependence, and generally occurred within three years of each other.

Project aggregation would be evaluated on a case-by-case basis and there is federal guidance to assist facilities and agencies when evaluating if multiple projects should be aggregated as one single permitting project. U.S. EPA policy on project aggregation is to ensure that NSR requirements are not circumvented by splitting up nominally-separate projects. Project aggregation policy by U.S. EPA does not address projects that are required for regulatory compliance. The available guidance primarily addresses voluntary projects, such as facility expansions or renovations.

For purposes of PAR 1304 subparagraph (f)(1)(E)~~(F)~~, South Coast AQMD will continue to follow federal guidance on project aggregation for NSR applicability determination by aggregating substantially related activities with a technical or economic dependence, which occurred within three years of each other. Aggregation will not be necessary for control projects required solely for regulatory compliance that do not have any technical or economic dependence to each other.

Project emissions for federal major NSR applicability purposes are evaluated differently than Regulation XIII. Regulation XIII permits are issued for each individual source or unit and does not consider the emission increases from other permitted actions or non-permitted actions when evaluating if the Regulation XIII threshold of one pound per day is exceeded.

Appendix B – RULE 1315 SUBDIVISION (g)

INTRODUCTION

Regulation XIII currently has an offsetting exemption for regulatory compliance under Rule 1304 paragraph (c)(4), for sources that are installed or modified solely to comply with local, state, or federal air pollution regulations, provided there is no increase in the maximum rated capacity of the source. When sources are exempt from offsetting under Rule 1304, South Coast AQMD provides and tracks offsets from the District Offset Accounts for Federal NSR Equivalency or "Internal Bank" for nonattainment air contaminants according to Rule 1315 – Federal New Source Review Tracking System (Rule 1315). In addition to tracking for federal NSR equivalency, South Coast AQMD tracks emission increases to demonstrate compliance with the state NSR requirement of no net increase. In addition to the state and federal offsetting equivalency demonstration, Rule 1315 subdivision (g) – California Environmental Quality Act Backstop Provisions requires tracking of all increases and decreases in PTE for major and minor sources that were exempt from providing offsets under Rule 1304 or received offsets pursuant to Rule 1309.1. The purpose of Rule 1315 subdivision (g) is to ensure the cumulative net emission increases in any given year remain below the emission increases that were analyzed in the California Environmental Quality Act (CEQA) document for Rule 1315. The cumulative net emission increases for each year must remain below the threshold in Rule 1315 Table B in order for the Executive Officer to be able to continue to issue permits pursuant to Rule 1304 or Rule 1309.1. The September 3, 2021 Governing Board Status Report on Regulation XIII demonstrated that the actual and projected cumulative net emission increase of each nonattainment air contaminant at major and minor sources remain below the thresholds in Rule 1315 Table B. Based on the average increases and decreases in PTE at major and minor sources from 2011 through 2019 (summarized below) and the PM_{10} emission increases of 0.24 tons per day from sources that could potentially use the proposed BACT exemption in Rule 1304 and be exempt from offsetting for regulatory compliance under Rule 1304 paragraph (c)(4), the PM_{10} thresholds in Rule 1315 Table B are not expected to be exceeded.

Rule 1315 Subdivision (g) Analysis

To ensure the PM_{10} thresholds in Rule 1315 Table B would not be exceeded, staff estimated the PM_{10} emission increases from sources that could potentially use the PAR 1304 BACT exemption and the offsetting exemption for regulatory compliance under Rule 1304 paragraph (c)(4). An analysis is not needed for SOx since the offsetting exemption under Rule 1304 paragraph (c)(4) will not apply to the SOx emission increases from sources that could potentially be exempt from BACT, because RTCs will be used to offset the SOx emission increases under Regulation XX. To project the potential impact on the PM_{10} thresholds in Rule 1315 Table B, the estimated PM_{10} emission increases from sources that could potentially be exempt from BACT and offsetting were added to the average PM_{10} PTE increase and decrease based on the historical PM_{10} PTE increases and decreases that occurred in 2011 through 2019 at major and minor sources reported in the annual status reports on Regulation XIII.[48] Table 3 – Cumulative Net Emission Increase of the annual Status Report on Regulation XIII presents the PTE increases and decreases for each nonattainment air contaminant that occurred at a major and minor facility which was issued a

[48] Status Report on Regulation XIII – New Source Review is presented to the Governing Board annually during the September Governing Board Meeting

permit pursuant to Rule 1304 or Rule 1309.1. Figure B-1 shows the PM_{10} increases and decreases in PTE, the cumulative net emission increase for each year, and the corresponding PM_{10} threshold in Rule 1315 Table B for 2011 through 2019. The methodology to calculate the PM_{10} emission increases from sources that could potentially use the proposed BACT exemption in Rule 1304 and be exempt from offsetting for regulatory compliance under Rule 1304 paragraph (c)(4) is described below.

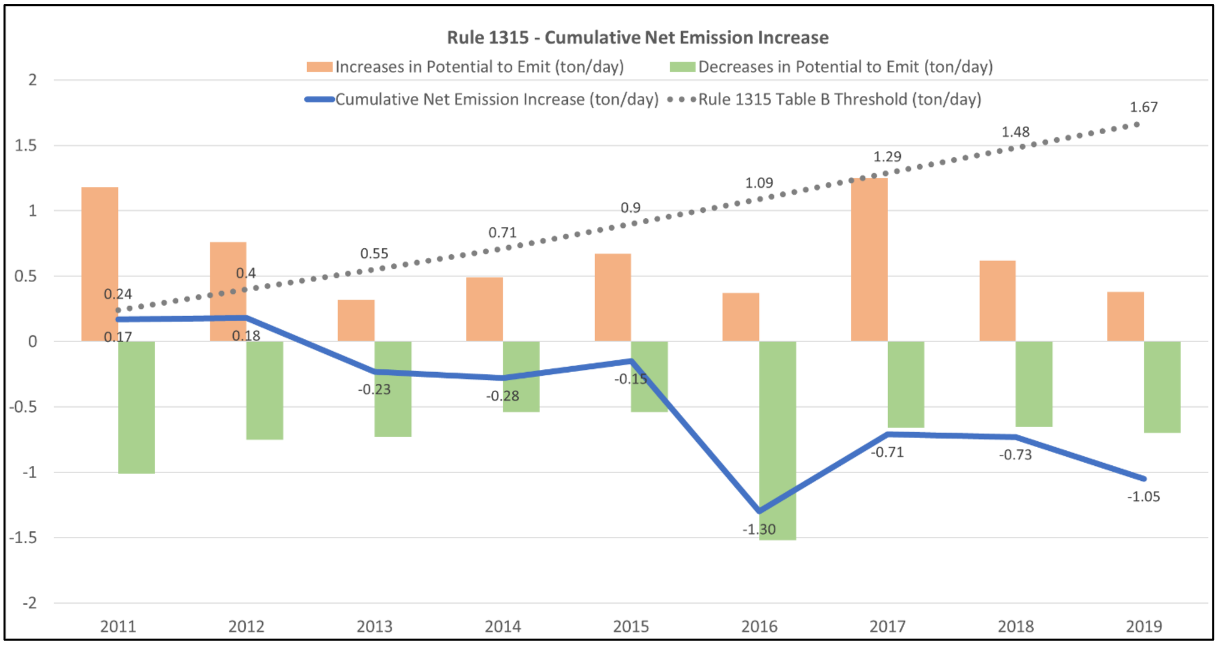

Figure B-1. Rule 1315 Cumulative Net Emission Increase for PM_{10} from 2011 through 2019

Calculation for PM_{10} Emission Increases

The PM_{10} emission increases from sources that could potentially use the PAR 1304 BACT exemption and the offsetting exemption for regulatory compliance in Rule 1304 paragraph (c)(4) were calculated according to the same methodology that will be used to calculate an emission increase for federal major NSR applicability. As described below, to calculate the PM_{10} emissions for each unit, the firing rate for each unit was used, as well as the higher heating value and total sulfur fuel content for the refinery fuel gas at each facility.

1. Calculate the fuel gas molar flow rate based on the unit firing rate and higher heating value of the fuel gas:

$$FG\left(\frac{lbmol}{hr}\right) = \frac{FR\left(\frac{MMBTU}{hr}\right) \times \frac{1E6\ BTU}{1\ MMBTU}}{HHV\left(\frac{BTU}{scf}\right) \times SV\left(\frac{scf}{lbmol}\right)}$$

where,

$$FG = Fuel\ Gas\left(\frac{lbmol}{hr}\right)$$

$$FR = Firing\ Rate\ of\ the\ Unit\left(\frac{MMBTU}{hr}\right)$$

$$SV = specific\ molar\ volume\ of\ an\ ideal\ gas\ at\ STP\left(\frac{scf}{lbmol}\right) = 385.3\ \frac{scf}{lbmol}$$

2. Calculate the moles of SO_2 in the fuel gas assuming total sulfur content is converted to SO_2:

$$n_{SO_2}\left(\frac{lbmol\ SO_2}{hr}\right) = \frac{x_{H_2S}(ppmv)}{1\ \times 10^6} \times FG\left(\frac{lbmol}{hr}\right)$$

where,

$$n_{SO_2} = molar\ flow\ rate\ of\ SO_2\ \left(\frac{lbmol}{hr}\right)$$
$$x_{H_2S} = total\ sulfur\ in\ fuel\ gas\ (ppmv)$$

3. Calculate the molar flow rate of SO_3 based on the SO_2 to SO_3 conversion specified by the catalyst manufacturer:

$$n_{SO_3}\left(\frac{lbmol\ SO_3}{hr}\right) = CF\left(\frac{1\ lbmol\ SO_3}{1\ lbmol\ SO_2}\right) \times n_{SO_2}\left(\frac{lbmol\ SO_2}{hr}\right)$$

where,

$$n_{SO_3} = molar\ flow\ rate\ of\ SO_3\ \left(\frac{lbmol\ SO_3}{hr}\right)$$
$$CF = conversion\ of\ SO_2\ to\ SO_3$$

4. Calculate the ammonium sulfate formed assuming all SO_3 is converted to ammonium sulfate based on the following chemical reaction:

$$2\ NH_3 + SO_3 + H_2O \xleftrightarrow{catalyst} (NH_4)_2SO_4$$

$$n_{(NH_4)_2SO_4}\left(\frac{lbmol\ (NH_4)_2SO_4}{hr}\right) = n_{SO_3}\left(\frac{lbmol\ SO_3}{hr}\right) \times \frac{1\ lbmol\ (NH_4)_2SO_4}{1\ lbmol\ SO_3}$$

where,

$$n_{(NH_4)_2SO_4} = molar\ flow\ rate\ of\ ammonium\ sulfate$$

5. Convert the molar flow rate to a mass flow rate using the molecular weight:

$$m_{(NH_4)_2SO_4}\left(\frac{lb\ (NH_4)_2SO_4}{hr}\right) = n_{(NH_4)_2SO_4}\left(\frac{lbmol\ (NH_4)_2SO_4}{hr}\right) \times MW_{(NH_4)_2SO_4}\left(\frac{lb\ (NH_4)_2SO_4}{lbmol\ (NH_4)_2SO_4}\right)$$

where,

$$m_{(NH_4)_2SO_4} = mass\ flow\ rate\ of\ ammonium\ sulfate$$
$$MW_{(NH_4)_2SO_4} = Molecular\ weight\ of\ ammonium\ sulfate = 132\ \frac{lb\ (NH_4)_2SO_4}{lbmol\ (NH_4)_2SO_4}$$

PM_{10} Calculation Example

The following is an example calculating the PM_{10} emission formed as ammonium sulfate from an SCR installation for a unit with a firing rate of 550 MMBtu/hr, a higher heating value of 1,330 btu/scf and a total sulfur concentration of 179 ppmv for the refinery fuel gas, and a 5 percent SO_2 to SO_3 conversion for the SCR catalyst:

$$\frac{550\ \times 10^6\ BTU}{hr} \times \frac{1\ scf\ FG}{1330\ BTU} \times \frac{1\ lbmol\ FG}{385.3\ scf} \times \frac{179\ lbmol\ H_2S}{1\ \times 10^6\ lbmol\ FG} \times \frac{1\ lbmol\ SO_2}{1\ lbmol\ H_2S} \times \frac{0.05\ lbmol\ SO_3}{1\ lbmol\ SO_2} = \frac{0.01\ lbmol\ SO_3}{hr}$$

$$\frac{0.01\ lbmol\ SO_3}{hr} \times \frac{1\ lbmol\ (NH_4)_2SO_4}{1\ lbmol\ SO_3} \times \frac{132\ lb\ (NH_4)_2SO_4}{1\ lbmol\ (NH_4)_2SO_4} = \frac{1.27\ lb\ (NH_4)_2SO_4}{hr}\ or\ \frac{0.015\ tons\ (NH_4)_2SO_4}{day}$$

In this example, the mass flow rate of ammonium sulfate formed corresponds to 0.015 tons per day of PM_{10} emissions.

Using this methodology and refinery specific data, the PM_{10} emissions for all PR 1109.1 units that were assumed to be associated with an SCR installation or modification that could potentially use the PAR 1304 BACT exemption and be exempt from offsetting under Rule 1304 paragraph (c)(4) was estimated to total 0.24 tons per day of PM_{10}.

Potential Impact on Rule 1315 Subdivision (g)

After estimating the PM_{10} emission increases from sources that could potentially use the PAR 1304 BACT exemption and be exempt from offsetting, staff analyzed the historical PM_{10} PTE increases and decreases at major and minor sources reported in the annual status reports on Regulation XIII. The assumptions used to analyze the potential impact on the PM_{10} thresholds in Rule 1315 Table B are summarized in Table B-1 below. The increases and decreases in PTE for PM_{10} reported for each year from 2011 through 2019 were used to calculate an average annual PM_{10} increase in PTE and an average annual PM_{10} decrease in PTE. The total PM_{10} emission increases of 0.24 tons per day from sources that could potentially use the proposed BACT exemption in Rule 1304 and be exempt from offsetting for regulatory compliance under Rule 1304 paragraph (c)(4) was assumed would occur throughout a 3-year span (2023 through 2025), which corresponds to an annual PM_{10} emission increase of 0.08 tons per day. The annual net emissions are estimated to be - 0.04 tons per day of PM_{10}, based on sum of the historical average increases and decreases in PTE and the additional emission increases from sources that could potentially be exempt from BACT and offsetting.

Table B-1. Assumptions Used to Estimate the Potential Impact on Rule 1315 Subdivision (g)

Description	PM_{10} Emissions (tons per day)
Annual PM_{10} Increases in PTE (based on 2011 – 2019 average)	0.67
Annual PM_{10} Decreases in PTE (based on 2011 – 2019 average)	-0.79
Annual PM_{10} emission increases from sources exempt from BACT and offsetting (based on 0.24 tons per day over a 3-year span)	0.08
Estimated Annual PM_{10} Net Emissions	**-0.04**

Using the assumptions in Table B-1, staff estimated the potential impact on Rule 1315 subdivision (g) as shown in Table B-2. Table B-2 compares the projected PM_{10} PTE increases and decreases and the cumulative net emission increase for each year to the corresponding threshold in Rule 1315 Table B. The additional yearly PM_{10} emission increase of 0.08 tons per day from sources that could potentially use the proposed BACT exemption in Rule 1304 and be exempt from offsetting for regulatory compliance under Rule 1304 paragraph (c)(4) was assumed to occur in 2023 through 2025, which corresponds with the total 0.24 tons per day. The cumulative net emission increase for each year is equal to the sum of increases and decreases in PTE of the corresponding year plus the cumulative net emission increase of the prior year. For example, the cumulative net emission increase for 2020 is based on the estimated PM_{10} emission increases and decreases in PTE in 2020 plus the cumulative net emission increase in 2019, as follow:

$$(0.67\ tons\ per\ day) + (-0.79\ tons\ per\ day) + (-1.05\ tons\ per\ day) = -1.17\ tons\ per\ day$$

Based on the PM_{10} PTE increases and decreases in 2011 through 2019 and the estimated PM_{10} emission increases from sources that could potentially use the proposed BACT exemption in Rule 1304 and be exempt from offsetting for regulatory compliance under Rule 1304 paragraph (c)(4), Table B-2 shows that the PM_{10} thresholds in Rule 1315 Table B are not expected to be exceeded.

Table B-2. Projected PM_{10} Emissions Compared to the Threshold in Rule 1315 Table B

Projected PM_{10} Emissions											
Description	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Increases in PTE (tons per day)	0.67	0.67	0.67	0.75	0.75	0.75	0.67	0.67	0.67	0.67	0.67
Decreases in PTE (tons per day)	-0.79	-0.79	-0.79	-0.79	-0.79	-0.79	-0.79	-0.79	-0.79	-0.79	-0.79
Cumulative Net Emission Increase (tons per day)	-1.17	-1.29	-1.40	-1.44	-1.48	-1.52	-1.63	-1.75	-1.87	-1.99	-2.11
Rule 1315 Table B Threshold (tons per day)	**1.86**	**2.05**	**2.24**	**2.43**	**2.63**	**2.83**	**3.03**	**3.32**	**3.43**	**3.63**	**3.83**

Appendix C – COMMENTS AND RESPONSES

COMMENT LETTER #1

Below is an excerpt of the comment letter received on September 17, 2021 from Torrance Refining Company LLC. Only responses to comments related to PARs 1304 and 2005 are addressed in this staff report. The full letter is addressed in the staff report for PR 1109.1.

Rule 1304 Comments

(f) Limited BACT Exemption

(f)(A) – *"The new or modified permit unit is located at a RECLAIM or former RECLAIM facility and is being installed or modified to comply with a South Coast AQMD rule to meet a specified NOx Best Available Retrofit Control Technology (BARCT) emission limit initially established before December 31, 2023;"*

The Draft Staff report for PAR 1304 indicates that Section (f)(1)(A) limits the BACT exemption to new or modified permit units being installed or modified at RECLAIM or former RECLAIM facilities to comply with a NOx BARCT rule to transition the NOx RECLAIM program to command-and-control regulatory structure. Therefore, it appears that the intent of this exemption is that it not only applies to BARCT emission limits, but Conditional, B-Plan and B-CAP emission limits as well. For avoidance of doubt, particularly in the permitting process, The District should clarify this Section accordingly. 1-1

Response to Comment 1-1:

Qualifying projects undertaken to meet the conditional NOx Concentration Limits and Alternative BARCT NOx Limits, such as concentration NOx limits for a B-Plan or B-Cap, may use the limited BACT exemption. PAR 1304 subparagraph (f)(1)(A) limits the BACT exemption for regulatory compliance with a NOx BARCT emission limit initially established before December 31, 2023 to transition the NOx RECLAIM program to a command-and-control regulatory structure. Conditional NOx Concentration Limits and Alternative BARCT NOx Limits are considered NOx BARCT emission limits specified in PAR 1304 subparagraph (f)(1)(A).

COMMENT LETTER #2

Below is ~~an excerpt of~~ the comment letter received on September 17, 2021 from Marathon Petroleum Corporation on behalf of Tesoro Refining & Marketing Company LLC. Only responses to comments related to PARs 1304 and 2005 are addressed in this staff report. The other comments are ~~full letter is~~ addressed in the staff report for PR 1109.1.

Tesoro Refining & Marketing Company LLC
A subsidiary of Marathon Petroleum Corporation

Los Angeles Refinery – Carson Operations
2350 E. 223rd Street
Carson, California 90810
310-816-8100

September 17, 2021

VIA Certified Mail and eMail (*wnastri@aqmd.gov*)
Return Receipt Requested

Wayne Nastri
Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Comments on SCAQMD Preliminary Draft Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Industries – And Related Proposed Rule 429.1 and Proposed Amended Rules 1304 and 2005 (Revision Date: August 20, 2021)

Dear Mr. Nastri:

On behalf of Tesoro Refining & Marketing Company LLC, a wholly owned subsidiary of Marathon Petroleum Corporation (collectively, "MPC"), MPC appreciates this opportunity to provide South Coast Air Quality Management District (SCAQMD) with comments on the Preliminary Draft Proposed Rule 1109.1 Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Industries (PR 1109.1) and the related proposed amended rules that were issued by the SCAQMD on August 20, 2021 (i.e., Proposed Rule 429.1 and Proposed Amended Rules 1304 and 2005).[1] Throughout the rulemaking process, MPC staff continues to be active participants in PR 1109.1 working group meetings and discussions with SCAQMD staff.

This set of comments, which supplements MPC's four previous comment letters submitted to SCAQMD on December 22, 2020, February 1, 2021, April 7, 2021, and May 12, 2021, focuses on several concerns that we outline below. Attachment 1 of this letter is a proposed mark-up of PR 1109.1 in red-line format that corresponds to MPC's comments.

1. **If U.S. EPA's Environmental Incentive Programs (EIP) Guidance[2] is applicable to the Best Available Retrofit Control Technology (BARCT) Equivalent Mass Cap Plan (B-Cap), environmental benefit can be demonstrated by other options and not only by the currently**

Please refer to the response to comments in the staff report for PR 1109.1

[1] SCAQMD, "Preliminary Draft Proposed Rule 1109.1", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pd_pr1109-1_75_day.pdf?sfvrsn=6
[2] EIP Guidance https://www.epa.gov/sites/default/files/2015-07/documents/eipfin.pdf

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proposed additional 10% reduction in the mass oxides of nitrogen (NOx) Emission Targets in PR 1109.1.

A. U.S. EPA's EIP Guidance does not apply to the B-Cap

As currently drafted, PR 1109.1 at subparagraph (g)(2)(C) includes a 10% reduction (environmental benefit) in Phase I, Phase II, and Phase III Facility BARCT Emission Targets for a Facility that decides to comply with the B-Cap option. MPC understands that the U.S. EPA has not affirmed that the B-Cap is subject to the requirements of U.S. EPA's January 2001 guidance document entitled "Improving Air Quality With Economic Incentive Programs" (EIP Guidance) and is currently evaluating the applicability of the EIP Guidance to the B-Cap.[3] U.S. EPA's EIP Guidance indicates that the B-Cap is not an Economic Incentive Program (EIP). For example, when describing the types of discretionary EIPs, the EIP Guidance includes statements such as the following:

- An EIP may be an emission trading program, a financial mechanism program, a program such as a clean air investment fund (CAIF) that has features of both trading and financial mechanism programs, or a public information program.[4]

- The four general types of EIPs are emission trading programs, financial mechanisms, CAIFs, and public information programs.[5]

- Unlike traditional CAA regulatory mechanisms, emission trading involves more than one party.[6]

Since the B-Cap does not involve trading, and clearly does not qualify as any of the other types of EIPs covered by the EIP Guidance, the B-Cap should not be subject to review under the EIP Guidance.

B. U.S. EPA's EIP Guidance allows flexibility for demonstrating environmental benefit

If U.S. EPA, however, ultimately determines that EIP Guidance applies to the B-Cap, the guidance allows flexibility to demonstrate the environmental benefit which can be something other than reducing surplus mass NOx emissions by at least 10%. Indeed, there are already multiple environmental benefits inserted into the B-Cap and I-Plan requirements as we explain below. "Environmental benefit" is defined as follows:

> *Environmental benefit–generally means ... increased or more rapid emission reductions. ... environmental benefit means reducing the amount of surplus emission reductions generated for use in the EIP by at least 10 percent. In addition, environmental benefit can also mean improved administrative mechanisms (e.g., that achieve emissions reductions from sources not readily controllable through traditional regulation), reduced administrative burdens on regulatory agencies that result in increased environmental benefits through other regulatory programs, improved emissions inventories that enhance and lend increased certainty to State planning efforts, and the adoption of emission caps which over time constrain or reduce growth-related emissions beyond traditional regulatory approaches.*

Please refer to the response to comments in the staff report for PR 1109.1

[3] SCAQMD states in its Draft Staff Report that "*U.S. EPA has initially commented that pursuant to U.S. EPA's January 2001 Improving Air Quality with Economic Incentive Programs, a 10 percent environment benefit will likely be required. Staff is continuing to discuss the elements of the B-Cap with U.S. EPA.*" (Draft Staff Report at p. 3-15)
[4] *Id.* at p. 15
[5] *Id.* at p. 18
[6] *Id.* at p. 78

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While the EIP Guidance requires demonstration of environmental benefit, the guidance "recognizes that the type of demonstration appropriate will depend on the goals and characteristics of the EIP [being] implemented."[7]

Furthermore, should the B-Cap be considered as a compliance flexibility trading EIP covered by the EIP Guidance, there are other sections of the EIP Guidance which indicate that the environmental benefit associated with a compliance flexibility trading EIP is not required to be a surplus 10% emission reduction, but may be an alternative demonstration as long as the EIP does not cover a nonattainment area that is needing and lacking an attainment demonstration, known as a "NALD area". As discussed below, South Coast AQMD is not an "NALD area" and therefore has flexibility to allow alternatives.

"NALD areas" are defined as follows:

> *Needing and lacking demonstration (NALD)--means a non-attainment area for which a State is currently required under the CAA to submit an SIP for attainment demonstration, but has not done so.*[8]

The SCAQMD has submitted, and EPA has approved, multiple ozone attainment demonstrations for the South Coast Air Basin, including most recently the 2016 Air Quality Management Plan ("2016 AQMP"), which states as follows:

> *The 2016 AQMP demonstrates how and when the South Coast Air Basin, as well as the Coachella Valley, will attain the ozone and PM2.5 standards as "expeditiously as practicable," but no later than the latest statutory attainment date.*[9]

Therefore, the South Coast Air Basin is not a "NALD area" in which an alternative environmental benefit would be prohibited under the EIP Guidance.

Other options for meeting the environmental benefit requirement in the EIP Guidance include the following, some of which are already embedded within the rule framework of the B-Cap and I-Plan as noted in brackets:

- *showing greater or more rapid emission reductions due to trading (e.g., early reductions)* – [The I-Plan for B-Cap Facilities includes a provision for earlier reductions by January 1, 2024 of at least 50% of the total required emission reduction under PR 1109.1 as compared to the schedule for meeting the limits in Tables 1 and 2.]

- *showing other environmental management improvements* – [A Facility that permanently decommissions a Unit and not replacing it with a functionally similar Unit or that reduces its annual throughput or NOx concentration to meet the B-Cap will deliver other important emissions reductions to the South Coast Air Basin beyond NOx, including other criteria pollutants such as VOC, SO_2, and fine particulate matter, as well as benefiting AB-617 communities.]

Please refer to the response to comments in the staff report for PR 1109.1

[7] *Id.* at p. 56
[8] *Id.* At p. 108
[9] 2016 AQMP at p. ES-10

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- *improved administrative mechanisms (for example, your EIP achieves emissions reductions from sources not readily controllable through traditional regulation)*
- *reduced administrative burdens on regulatory agencies that lead to increased environmental benefits through other regulatory programs*
- *improved emissions inventories that enhance and lend increased certainty to State planning efforts*
- *the adoption of emission caps which over time constrain or reduce growth-related emissions beyond traditional regulatory approaches* – [The B-Cap contains restrictions on how new Units are to be added such that a Facility's NOx emissions are less than the Facility's Emission Targets.]
- *for multi-source cap and trade program or a single source cap and trade program, includes a declining cap.*

These provisions make clear that alternative environmental benefits are permissible under the EIP Guidance under certain circumstances. Moreover, some of these alternative environmental benefits allowed for under the EIP guidance are already included in the B-Cap and I-Plan as currently drafted, including an accelerated schedule for achieving the majority of the NOx emissions reductions well in advance of what is otherwise required without a B-Cap. Additionally, collateral emissions reductions in other criteria and toxic air pollutants will result from decommissioning and/or reducing the annual utilization or throughput of equipment to meet the B-Cap that improve emissions inventories, represent an emissions cap that constrains or reduces growth-related emissions, and includes a declining cap.

Therefore, if it is ultimately determined by U.S. EPA that the EIP Guidance does indeed apply to the B-Cap, the B-Cap and I-Plan framework for both early emissions reductions as well as collateral pollutant emissions reductions satisfies this environmental benefit obligation as described above. To ensure the rule credits a Facility for these environmental benefits, MPC proposes a new subparagraph (i)(3)(H) and other rule revisions in Attachment 1 of this letter that require a Facility electing to comply with a B-Cap to demonstrate environmental benefit using allowable options in the EIP Guidance.

Please refer to the response to comments in the staff report for PR 1109.1

2. Regulatory certainty is necessary to demonstrate that emission reduction projects will not trigger Federal New Source Review for PM_{10} or $PM_{2.5}$.

As SCAQMD understands, many of the proposed low NOx BARCT limits under PR 1109.1 cannot be achieved without selective catalytic reduction (SCR). MPC and other stakeholders have previously pointed out that installation of SCR may result in increases in emissions of particulate matter less than 10 microns (PM_{10}) and particulate matter less than 2.5 microns ($PM_{2.5}$) (PM_{10} and $PM_{2.5}$ collectively referred to as "fine particulate matter") such that the retrofit project could trigger a "major modification" under U.S. EPA's New Source Review (federal NSR) program, and thus require Best Available Control Technology (BACT).[10]

2-1

[10] See MPC's Fourth Set of Comments on SCAQMD Revised Draft of Proposed Rule 1109.1-Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Industries (Revision Date December 24, 2020) (dated May 12, 2021). MPC previously provided data from emissions testing using reference test methods at a heater with SCR technology to reduce NOx emissions. The resulting emissions factor for fine particulate matter, when combined with the heater input duty and a lower fine particulate matter emissions factor to represent pre-SCR baseline operations, may result in a significant emissions increase subject to the 40 CFR §52.21 and/or SCAQMD 1325 as a major modification.

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In SCAQMD's Preliminary Draft Staff Report for Proposed Amended Rules 1304 and 2005, SCAQMD states:

> *For the purpose of determining federal major NSR applicability, PM and SOx emission increases may be estimated according to the calculations below. The following approach to calcualte [sic] PM and SOx emissions for the purpose of determining NSR applicability has been discussed without opposition with U.S. EPA.*
>
> * * *
>
> *The calculation method will be used in lieu of conducting a source test for PM_{10} emissions when a facility submits a permit application for SCR installation or modification.*

SCAQMD also provides an example calculation for determining the ammonium sulfate as fine particulate matter that may form as a result of installing SCR.[11]

For reference, the South Coast Basin is designated in attainment with the PM_{10} NAAQS and is subject to 40 CFR § 52.21 for the Prevention of Significant Deterioration (PSD) permit program. SCAQMD Rule 1325 - Federal $PM_{2.5}$ New Source Review Program – applies to new and modified major sources that trigger the federal NSR threshold for $PM_{2.5}$. Rule 1325 incorporates and adopts U.S. EPA requirements for $PM_{2.5}$, which is designated nonattainment with the $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). Nowhere in Rule 1325 has this alternative calculation method been incorporated, referenced, or proposed to be added as part of PR 1109.1. If PR 1109.1 is approved in its current form and the alternative calculation method for determining fine particulate matter is only referenced in SCAQMD's Draft and Final Staff Report and not incorporated into Rule 1325, MPC is concerned that U.S. EPA cannot accept this alternative calculation method and shall require the use of U.S. EPA test methods that are referenced in Rule 1325 to demonstrate that an SCR project has not exceeded the federal major NSR threshold prior to issuance of the permit to construct.

The significance of having a federal major NSR determination for fine particulate matter is the additional amount of time (multiple years) a Facility would need to complete the permitting process as well as potentially requiring BACT for PM_{10} emissions or lowest achievable emission rate (LAER) for $PM_{2.5}$ emissions. In the case of MPC's Los Angeles Refinery, LAER technology for $PM_{2.5}$ could be a fuel gas sulfur treatment project that would add over $100 million in costs. Moreover, this additional cost to comply with PR 1109.1 has not been considered by SCAQMD in the cost-effectiveness of NOx BARCT.

2-1 (Continued)

3. Compliance schedules should be dependent on the issuance date of a Permit to Construct, and not on the date of permit application submittal.

Some of the key compliance deadlines in PR 1109.1 for meeting emissions limits and to complete emissions reduction projects are based on a specified duration of time after the Facility submits its Permit to Construct application instead of being based on a time frame after issuance of a Permit to Construct by the SCAQMD. A Facility cannot commence and complete emissions reduction projects for PR 1109.1 without having a Permit to Construct issued by SCAQMD. There are no deadlines or time frames in PR 1109.1 that SCAQMD must meet for issuing a permit after an application has been submitted. As a result, a Facility may not be able to meet a compliance deadline if SCAQMD does not issue an air permit in a timely manner. Based on historical projects, SCAQMD can take several years to issue a Permit to

Please refer to the response to comments in the staff report for PR 1109.1

[11] SCAQMD, "Preliminary Draft Staff Report, Proposed Amended 1304 - Exemptions, Proposed Amended Rule 2005 – New Source Review for RECLAIM", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/par-1304-and-par-2005/pdsr-par-1304_2005-aug-2021.pdf?sfvrsn=16, pages 2-6 and 2-7

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Construct, and the facility has no certainty when the permit will be ultimately issued. Therefore, any deadlines in PR 1109.1 that are currently in the rule language based on permit application submittal dates should be changed to a time frame after issuance of the permit(s). MPC requests the following deadlines and corresponding language be changed or removed in PR 1109.1:

- Subparagraph (g)(2)(I) contains a compliance date for an approved B-Cap that is *"... no later [than] 54 months from South Coast AQMD Permit Application Submittal Date for all other phases of the selected I- Plan option in Table 6 to meet the Phase I, Phase II, or Phase III Facility BARCT Emission Targets."* Since Table 6 already lists compliance dates that are either a specific date or based on permit issuance, this requirement is unnecessary.

- Paragraph (g)(5) requires a Unit complying with certain emission limits in subdivision (d) and that fails to submit a complete permit application by the specified date in PR 1109.1 to *"... meet the applicable Rule 1109.1 Emission Limits no later than 36 months after the South Coast AQMD permit application submittal date."* This provision is effectively requiring a facility to commence construction on projects necessary to meet PR 1109.1 without a Permit to Construct being issued by SCAQMD if the permit is not issued within a certain time frame, thus potentially forcing non-compliance that is outside the facility's control. Other requirements in PR 1109.1 establish when these limits shall be met following issuance of a Permit to Construct. Those should remain in the case that a complete permit application is not submitted by the specified date in PR 1109.1. Paragraph (g)(5) should be removed in its entirety.

Related to the compliance schedule language in subdivision (g), subparagraphs (g)(2)(B) through (G) do not provide a compliance date and are duplicating the required elements in subdivision (i) for Plan submittals. Since subparagraph (g)(2)(A) already references provisions in subdivision (i) and the corresponding compliance date, MPC requests removal of subparagraphs (g)(2)(B) through (G) because they are duplicative and confusing.

4. The compliance date in PR 1109.1 for emission limits with multi-day rolling average periods should be clarified to represent the first day of the rolling average period.

PR 1109.1 contains some emission limits that have multi-day rolling average periods, such as concentration limits on a 7-day rolling average or 365-day rolling average as well as mass emission limits on a 365-day rolling total (i.e., Facility BARCT Emission Target). The compliance date in PR 1109.1 for these longer averaging periods represents the first day of measuring or calculating emissions such that after the last day of the limit's averaging period, the first compliance demonstration is made. For example, Table 6 for I-Plan Option 4 lists a date of January 1, 2024 as the compliance date for meeting the Phase I BARCT Emission Target. The first demonstration of compliance with the tons-per-year BARCT Emission Target will be after December 30, 2024, which is 365 days from January 1, 2024, noting that 2024 is a leap year with 366 days.

This clarification should be made for all multi-day rolling average periods, and MPC recommends adding a definition in subdivision (c) for "Compliance Date" that reflects this. See Attachment 1 for proposed language to define this term.

<u>Please refer to the response to comments in the staff report for PR 1109.1</u>

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5. The CO limit overlap provision in paragraph (d)(7) should extend to other CO limits PR 1109.1 in addition to those in Tables 1 and 2

Paragraph (d)(7) requires that a carbon monoxide (CO) emission limit established in a SCAQMD Permit to Operate (PTO) for a Unit continue to meet that PTO limit instead of the CO emission limit *"... specified in Table 1 or Table 2."* SCAQMD has established CO limits in other provisions of PR 1109.1 besides those listed in Table 1 and Table 2 that should also be subject to the overlap provision in paragraph (d)(7). Where these CO limits are generally drawn from Table 1 or Table 2 but are not directly referenced, this may lead to confusion on applicability of the CO limit if paragraph (d)(7) does not specify whether the CO limit in a PTO or PR 1109.1 applies. See subparagraphs (d)(3)(A) through (C) and (d)(4)(A) through (C) for CO limits that do not refer directly to Table 1 or Table 2 and thus are not currently covered by the (d)(7) overlap. Also, the interim CO limits in paragraph (f)(1) in Table 4 should be subject to paragraph (d)(7).

MPC recommends broadening the language in paragraph (d)(7) to clarify that CO emission limits in an applicable PTO limit shall continue to be met in lieu of those in PR 1109.1. See Attachment 1 for proposed revisions to paragraph (d)(7).

Additionally, in regard to CO limits in PR 1109.1, MPC notes the following proposed corrections:

- Paragraph (e)(2) for a B-Cap includes the phrase *"... that elects to meet the NOx and CO emission limits in an approved B-Cap in lieu of meeting Table 1 and Table 2 NOx concentration limits..."*. Under PR 1109.1, a B-Cap is for NOx only and is not also for CO. The term "and CO" must be removed from paragraph (e)(2). This change would make the language consistent with that in paragraph (e)(1) for a B-Plan that does not contain the "and CO" term.

- Paragraph (j)(3) refers to CO emission limits in Table 3. Table 3 does not have CO limits but Table 4 does, so paragraph (j)(3) should instead reference Table 4.

6. Compliance schedule requirements in paragraphs (d)(8) and (d)(9) for Table 1 or Table 2 limits should be incorporated into subdivision (g) (Compliance Schedule) and remove potential conflicts.

Paragraph (d)(8) establishes a schedule to demonstrate compliance with applicable limits in Table 1 or Table 2 that are less than a 365-day averaging period. The schedule is to demonstrate compliance with these limits *"... six months after, either the date the South Coast AQMD Permit to Operate is issued, 36 months after the Permit to Construct is issued or completion of a compliance demonstration source test, whichever is sooner."* However, clauses (g)(1)(B)(i) and (ii) specify different compliance schedules for Table 1 limits, as follows: *"(i) No later than 36 months after a South Coast AQMD Permit to Construct is issued; or (ii) No later than July 1, 2023 if a permit application was not required as specified in subparagraph (g)(1)(A)."* These two schedules conflict and will lead to confusion as to when compliance needs to be demonstrated for Table 1 limits. MPC recommends incorporating paragraphs (d)(8) and (d)(9) as well as other compliance schedule requirements in subdivisions (d) and (e), as applicable, into subdivision (g) titled "Compliance Schedule," such that all compliance schedule requirements are located in one rule subdivision.

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Relatedly, it is unclear when a permit application is required or is not required under subparagraph (g)(1)(B)(ii). Generally, a permit application will be needed to incorporate the Table 1 limit, but it is unclear when a permit application is not required. MPC requests regulatory clarification on this issue.

Paragraph (d)(9) establishes a compliance schedule for limits with a 365-day rolling average, but this paragraph does not state which limits this schedule applies to. Although MPC presumes this paragraph is intended to address limits in Table 1 or Table 2, as with paragraph (d)(8), SCAQMD needs to clearly state this. Otherwise, this paragraph could be misconstrued as establishing a compliance schedule for a B-Plan or B-Cap, which have 365-day rolling average limits, instead of the schedule specified in paragraph (g)(2) that explicitly addresses the compliance schedule requirements for a B-Plan or B-Cap. See Attachment 1 for proposed revisions to paragraph (d)(9).

7. PR 1109.1 sets an inappropriate early shutdown deadline for permanently decommissioned units under the B-Cap.

Clause (e)(2)(D)(i), excerpted below, requires that a Unit scheduled to be permanently decommissioned as part of an approved B-Cap surrender the SCAQMD PTO by specified dates.

> *(i) Surrender the South Coast AQMD Permit to Operate no later than the compliance date for Phase I in I-Plan Option 4 and no later than the permit submittal date for all other phases in an approved I-Plan; ...*

This clause specifies that the "compliance date" for Phase I in I-Plan Option 4 is the permit surrender deadline, but SCAQMD uses a term "permit submittal date" as the deadline for the other I-Plan phases. It is unclear whether "permit submittal date" is referring to a permit application by the Facility, a permit issued by SCAQMD, or some other permit-related action. MPC believes that the permit surrender deadline should not be at any time before the compliance date in Table 6 for all of the I-Plan options in order to provide sufficient time to complete projects that may be important to allow for decommissioning of a Unit prior to the compliance date for an I-Plan phase. MPC recommends simply referring to the listed compliance dates in Table 6. See Attachment 1 for proposed revisions to clause (e)(2)(D)(i).

Related to this issue, no description exists in PR 1109.1 or the Draft Staff Report for the process to "surrender" a permit. MPC requests additional clarification on the process to surrender or inactivate a PTO for a permanently decommissioned unit.

Finally, clause (e)(2)(D)(iii) reads as if a Unit cannot be sold to a company that is located within the South Coast Air Basin instead of reflecting the intent that the Unit cannot be operated in the South Coast Air Basin. See Attachment 1 for proposed revisions to clause (e)(2)(D)(iii) to reflect this intent.

8. A BARCT B-Cap fully realizes the emission reduction objectives of PR 1109.1, and demonstration with a B-Cap's BARCT Emission Targets is met by monitoring and reporting of the Facility's actual emissions.

The B-Cap is an alternative compliance option provided for under PR 1109.1 that can also achieve the NOx emission reductions. As SCAQMD notes in its August 2021 Preliminary Draft Report for PR 1109.1 and Proposed Rescinded Rule 1109 (Draft Staff Report), "*The B-Cap achieves the same emission reductions as if the facility complied directly with the proposed NOx limits.*"[12] MPC supports the

[12] SCAQMD, "Preliminary Draft Staff Report, Preliminary Draft Proposed Rule 1109.1", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pdsr_pr-1109-1_75_day.pdf?sfvrsn=6, page Ex-1

<u>Please refer to the response to comments in the staff report for PR 1109.1</u>

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SCAQMD inclusion of the B-Cap option in paragraph (e)(2) of PR 1109.1 to provide an alternative means of demonstrating equivalent cumulative NOx emissions reductions such that the facility may achieve these emissions reductions in a safer and more cost-effective way. However, SCAQMD includes an additional demonstration in the Implementation Compliance Plan (I-Plan) that requires the facility to show that the planned NOx emissions reduction projects in concert with any other strategies to reduce mass emissions will, prospectively, meet the applicable Emission Target. This additional prospective demonstration is summarized as follows:

1. Select an Alternative BARCT NOx Limit on a concentration basis for every unit, which for heaters and boilers must be on a 24-hour rolling average, per subparagraph (e)(2)(B) of the rule. This value cannot exceed the Maximum Alternative BARCT NOx Limits for a B-Cap in Table 3.

2. Accept a permit limit for the Alternative BARCT NOx Limit for every unit, per subparagraph (e)(2)(C) of the rule.

3. Calculate the Phase I, Phase II, or Phase III BARCT B-Cap Annual Emissions (B-Cap Annual Emissions) by requiring, in part, the use of the Alternative BARCT NOx Limit per subparagraph (g)(2)(F) and following the calculation method in Attachment B of the rule at Subsection B-6.1.

4. Demonstrate in an Implementation Compliance Plan (I-Plan) and B-Cap submittal that the prospective B-Cap Annual Emissions, which incorporates and uses the Alternative BARCT NOx Limit for each unit and other strategies to reduce mass emissions, will not exceed the Emission Targets per subparagraph (g)(2)(G) and by the phased schedule for the chosen I-Plan option. The I-Plan is an additional requirement of the facility that elects to meet a B-Cap. The I-Plan is *"designed to maximize early emissions reductions, where feasible"* to meet each phase of the mass emission targets by deadlines established in Table 6 of PR 1109.1.[13]

The requirement to institute a unit-specific concentration limit such as an Alternative BARCT NOx Limit may be appropriate for the BARCT Equivalent Compliance Plan (B-Plan), which is a separate compliance option from the B-Cap that is based on establishing alternative NOx concentration limits. Conversely, a B-Cap is based on annual mass emissions from the units, which is a function of both the annual average NOx concentration and firing rates of each unit. Instituting a 24-hour average maximum NOx concentration for heaters and other units has no direct coupling to actual sustained emissions, since the 24-hour restricted maximum concentration is based on established worst-case conditions (highest design NOx concentration) that may occur over the course of the normal operating envelope of the emissions unit and control device. MPC's February 1, 2021 comment letter provides details on the inherent variability in NOx concentrations at a heater as well as variable firing rates that materially affect sustained actual emissions. Using a 24-hour maximum concentration to calculate an annual emissions rate for every unit will, by itself, result in a vastly unrealistic overestimate of the facility's future emissions.

For this reason, the Alternative BARCT NOx Limit should not be used solely to calculate the B-Cap Annual Emissions as other variables are important to calculate emissions. The calculation method for the facility's B-Cap Annual Emissions in Attachment B at Subsection B-6.1, excerpted below, allows the incorporation of "emissions reductions from reduced throughput, efficiency, reduced capacity, and any

Please refer to the response to comments in the staff report for PR 1109.1

[13] SCAQMD, "Preliminary Draft Staff Report, Preliminary Draft Proposed Rule 1109.1", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pdsr_pr-1109-1_75_day.pdf?sfvrsn=6, page Ex-1

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other strategy to reduce mass emissions." A facility should not be penalized for operating at NOx concentration levels that are lower than the 24-hour Alternative BARCT NOx Limit at its heaters and other units when it is able to practically do so and when operating conditions allow. This and other related strategies to reduce annual NOx emissions is an important and necessary element of the B-Cap Annual Emissions calculation that would be considered in the "(Throughput or Other Reductions)" aspect of the equation.

$$\text{Phase I BARCT B} - \text{Cap Annual Emissions}_{B-Cap} = \sum_{i=1}^{N} \left(\frac{C_{\text{Phase I Alternative BARCT Emission Limit}}}{C_{\text{Baseline}}} \times \text{Baseline Unit Emissions} \right)_i + (0_{\text{Decommissioned Units}})_i - (\text{Throughput or Other Reductions})$$

Where:

N	= Number of included units in B-Cap under Phase I
$C_{\text{Phase I Alternative BARCT Emission Limit}}$ =	The applicable Alternative BARCT NOx Limit in an approved B-Cap for unit i included in the B-Cap
C_{Baseline}	= Representative NOx Concentration as defined in subdivision (c) for unit i included in the B-Cap
Baseline Unit Emissions =	Baseline Unit Emissions as defined in subdivision (c) and for unit i included in the B-Cap
Throughput or Other Reductions =	Emission reductions occurred from other than reducing the concentration limit.

For planning purposes in the B-Cap submittal, an appropriate and representative calculation of B-Cap Annual Emissions is based on the firing rate and concentration of each unit that incorporates emissions reductions projects and other strategies to reduce mass emissions. This basic demonstration of future emissions scenario(s) is not the means for which compliance with the Emission Targets is ultimately met, but rather it serves as a means of SCAQMD reviewing and approving the B-Cap and I-Plan for implementation. Compliance with the B-Cap as a practical matter is a matter of the facility showing that its actual NOx emissions are less than the applicable Emission Targets. MPC requests that the SCAQMD document their agreement that the "(Throughput or Other Reductions)" aspect of the equation above can include a variety of different means to achieve the Emission Targets, including operating at lower annual-average emissions levels.

9. The 24-hour rolling average associated with PR 1109.1 NOx concentration limits for boilers and process heaters is not reasonable as it is not representative of inherent operational variability associated these units.

Maximum NOx concentration limits are established in PR 1109.1 for boilers and process heaters on a 24-hour rolling average. These limits and the associated short-term averaging period are not proven and/or are infeasible for some refinery heaters. Burner manufacturers generally base their NOx emissions specifications and guarantees on set operating conditions, including combustion air temperature, fuel gas composition, and excess air going to the burner(s). Refineries have dynamic operating conditions and it is

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common for process heaters to run at a wide operating envelope that deviate from the ideal set of conditions that are used for burner NOx concentration specifications.

Over a longer averaging period like a 365-day rolling average, the heater's operating conditions may more closely align with those presumed by the burner manufacturer in establishing the NOx emissions guarantee, but a 24-hour rolling average limit may not always be met when there are hydrogen and other compositional and heating value fluctuations in refinery fuel gas, changes in oxygen content within the heater, or other real-world variabilities in operating conditions that can cause the NOx concentration to increase above the limit in the short-term. MPC proposes that the averaging period for NOx concentration limits at boilers and process heaters be changed from 24-hour rolling average to 365-day rolling average.

10. SCAQMD's approval process for an I-Plan, B-Plan, and B-Cap should be granted to the Facility if the information described in paragraph (i)(4) is provided.

Paragraph (i)(4) and its references to paragraphs (i)(1) through (3) contain the prescriptive informational elements for the Facility to provide in an I-Plan, B-Plan, or B-Cap to be approved by SCAQMD. Paragraph (i)(4) provides for SCAQMD to approve or disapprove the I-Plan, B-Plan, or B-Cap based on whether the owner or operator demonstrates that certain requirements have been met. In general, the information required in these plans are prescriptive in nature, consisting of data and calculations, such that SCAQMD should not disapprove a Plan submittal if it contains this information. However, per subparagraph (i)(4)(C), the Facility gets only one opportunity to correct any deficiencies and re-submit a Plan, and then if SCAQMD disapproves the Plan, the Facility must comply with the schedule in paragraph (g)(1) which excludes the alternative compliance demonstration of a B-Plan or B-Cap. This mandatory and stringent off-ramp from a B-Plan or B-Cap to instead meet the Table 1 limits is unworkable to a Facility that has made long-term plans to meet one of these alternative compliance methods. MPC proposes changes to paragraph (i)(4) in Attachment 1 of this letter that:

- Provides SCAQMD 30 days to conduct an initial administrative completeness review of the Plan(s);
- Clarifies SCAQMD shall not disapprove a Plan if the Facility provides the required information in the rule;
- Removes the mandatory off-ramp for a Facility to meet the compliance schedule in paragraph (g)(1) instead of (g)(2); and
- Subjects an I-Plan, B-Plan, or B-Cap to Rule 221 – Plans.

MPC has also included in Attachment 1 of this letter proposed corrections and updates to subdivision (i) to address other updates, as summarized below:

- New subparagraphs (i)(1)(A), (i)(2)(A), and (i)(3)(A) are introduced to clarify if multiple Facilities are covered in a single I-Plan, B-Plan, and B-Cap due to being under the same ownership.
- Subparagraphs (i)(1) and (i)(3) should reference the BARCT Equivalent Mass Emissions Cap for the B-Cap instead of the Alternative NOx BARCT Limit for a B-Plan as the key approach to address equivalent emissions reductions under PR 1109.1.

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- Subparagraph (i)(1)(D) is duplicative of subparagraph (i)(1)(F) and should be removed.

- Subparagraph (i)(1)(F) references the wrong citation for specification of the I-Plan option, so this reference has been updated.

- Subparagraph (i)(3)(D), shown as subparagraph (i)(3)(E) in Attachment 1 of this letter, restricts reductions in mass emissions to those only associated with a reduction in throughput, but Attachment B at Section B-6 allows for other reductions to be incorporated into the BARCT Annual Emissions calculation. The language in this subparagraph is updated to be consistent with Section B-6.

- Subparagraph (i)(3)(E), shown as subparagraph (i)(3)(F) in Attachment 1 of this letter, incorrectly references the term "BARCT Equivalent Mass Emissions" for a B-Plan instead of the term "BARCT B-Cap Annual Emissions" for a B-Cap.

- Subparagraph (i)(4)(B), shown as subparagraph (i)(4)(D) in Attachment 1 of this letter, allows only 30 days for a Facility to correct deficiencies and resubmit a Plan. MPC requests the more reasonable 60 days instead of 30 days in the event that the deficiencies noted by SCAQMD require additional time to develop new information and prepare a resubmittal.

- Clause (i)(5)(C)(iv) requires a modification to the Plan if an emission reduction project is moved to a different implementation phase or is removed from a phase. The compulsory information required in subparagraph (i)(1) through (4) does not include the time frame for emission reduction projects, so it should not be a criterion for requiring a modification to the Plan. The permitting process is a more appropriate means of addressing changes that involve emission reduction projects.

11. The interim limit for a B-Cap in paragraph (f)(3) requires additional specificity on the compliance time frame.

Paragraph (f)(3), excerpted below, establishes a requirement to maintain emissions in aggregate below the Baseline Facility Emissions.

> *"(3) An owner or operator of a Former RECLAIM Facility that elects to comply with an approved B-Cap shall not operate any unit included in the approved B-Cap unless the NOx emissions for all units in the B-Cap are in aggregate at or below the Baseline Facility Emission."*

MPC requests that SCAQMD clarify the compliance demonstration elements of this rule provision, specifically to: (1) identify the compliance date (also see item 6 regarding compliance dates), (2) stipulate the averaging period (i.e., 365-day rolling average), and (3) clarify when the interim limit is no longer applicable.

12. Certain provisions for time extension requests in subdivision (h) should be adjusted to support timely approvals.

Time extensions for an approved I-Plan may be requested per paragraph (h)(2) under certain listed criteria. MPC requests the following changes that will allow for an improved process to qualify for and be granted time extensions:

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- Clause (h)(2)(C)(i) allows an owner or operator to apply for a time extension if it took 24 months for SCAQMD to issue a permit after submittal of a permit application. MPC requests that this time frame be changed from 24 to 18 months to provide a more reasonable permitting time frame for projects needed to meet PR 1109.1.

- Paragraph (h)(4) allows SCAQMD 60 days to act on a time extension request. MPC requests that this time frame be changed to 30 days in order to provide sufficient time for an owner or operator to respond to any deficiencies noted by SCAQMD in a Plan submittal before a compliance deadline.

- Paragraph (h)(7) lists two deadlines for a Facility to meet emission limits if a time extension is disapproved. MPC proposes to add the phrase "whichever is later" at the end to provide certainty on the applicable deadline.

13. Key averaging time and testing schedule requirements in the emissions testing provisions need to be revised.

MPC offers the following proposed changes to address concerns with the testing provisions in subdivision (k).

- MPC proposes a new subparagraph to address the potential conflict between the source test requirements in Tables 7 and 8 of PR 1109.1 and those in a SCAQMD PTO. See Attachment 1 for new paragraph (k)(3).

- The source test protocol for paragraph (k)(7) requires *"an averaging time of at least 2 hours."* The Draft Staff Report at page 3-23 states that the averaging time is *"no less than 15 minutes but no longer than 2 hours."* MPC proposes to change the language in subparagraphs (k)(7)(A) and (B) to that shown as subparagraphs (k)(8)(A) and (B) in Attachment 1 of this letter, which reflects the draft staff report.

- The timing in subparagraph (k)(7)(A) to submit a source test protocol relative to receiving a Permit to Construct may not be possible, because the Facility may not have sufficient detailed information for a complete protocol if the Unit is still being designed. Similarly, the timing in subparagraph (k)(7)(C) to conduct a source test within 90 days upon approval of the source test protocol may not be possible, because the air pollution control equipment may not be installed and fully operational by that time. To address this, MPC proposes that the source test protocol timing is a function of the source test itself in order to ensure that the unit is operational (e.g., that it has resumed stable operations after completion of an emission reduction project) and is ready for testing. See Attachment 1 for revisions to subparagraphs (k)(7)(A) and (B) which are shown as subparagraphs (k)(8)(A) and (B) in Attachment 1 of this letter.

- MPC proposes to change the deadline for submitting a source test report in paragraph (k)(11) from 60 to 90 days of completion of the source test. Due to the increased number of source testing obligations pursuant to PR 1109.1 and the fact that meeting this requirement is primarily a function of the contracted and SCAQMD-approved source testing firm, an additional 30 days is needed to address the increased workload and potential delays in reporting by a source testing firm.

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14. The provision to limit the total amount of NOx emission reductions from decommissioned units to 15% under a B-Cap new unit exemption is unreasonably low.

Subparagraph (e)(2)(F) contains restrictions on adding a new unit under the B-Cap. Of particular concern is clause (e)(2)(F)(iv) that restricts the total amount of NOx reductions from decommissioned units to 15 percent of the Final Phase Facility BARCT Emission Target. From the Draft Staff Report, it appears that this clause is attempting to address SCAQMD's concerns with a unit being replaced with a "functionally similar unit outside the B-Cap".[14] To address this concern, MPC proposes to revise the clause to address units that are decommissioned but not replaced with a functionally similar Unit. Accordingly, this will appropriately delineate between projects that are being completed to satisfy environmental rule obligations and unit replacements. With this restriction in place, MPC believes that the 15% threshold should be higher and it should be based on the Total Facility NOx Emissions Reductions, and not the Final Phase BARCT Emission Target, which compares emission reductions for decommissioned units to total reductions. See Attachment 1 for a proposed revision to clause (e)(2)(F)(iv).

Relatedly, MPC notes that clause (e)(2)(F)(i) refers to *"Equivalent Mass Emission"* instead of *"B-Cap Annual Emissions."* The former term is for a B-Plan and is not applicable to a B-Cap. MPC has updated this clause in Attachment 1 of this letter.

15. The future established NOx limits for small refinery boilers and heaters is not based on BARCT.

SCAQMD includes 5 ppmv and 9 ppmv NOx limits for small refinery boilers and heaters, respectively, at subparagraphs (d)(3)(C) and (d)(4)(C), that take effect in the future. These limits are not based on a current technology that is safe, technically feasible, and cost-effective, which are compulsory elements of a control technology to be considered for BARCT. Instead, SCAQMD states that the limits are based on emerging technologies and that staff *"... will monitor the development of emerging technologies and will include in the Resolution a commitment to report on the status of the emerging technologies in 2029 and conduct a technology assessment if these technologies are not being commercialized."*[15] It is practically impossible to know if a technology will be technically feasible, safe to operate, and cost-effective for small refinery boilers and heaters ten years from now or even further into the future. By establishing such limits in this rulemaking, it goes against the Health & Safety Code that requires technical feasibility and cost effectiveness be demonstrated in order for a control technology to be BARCT.

MPC believes these future limits that are not based on BARCT should be removed from the rule. At the least, MPC recommends that SCAQMD make the future effective date of these limits dependent on the results of SCAQMD's status report in 2029 that addresses whether or not these emerging technologies are technically feasible and cost-effective for BARCT as of 2029 or later.

16. Potential confusion between the RECLAIM transition and B-Cap related limits and associated calculation and monitoring methods needs to be addressed in the rule.

MPC requests clarity as to when a Facility is operating after the effective date of PR 1109.1 but before it becomes a Former RECLAIM Petroleum Refinery. Specifically, PR 429.1 addresses startup and shutdown emissions for PR 1109.1 but only applies to a Former RECLAIM Petroleum Refinery. Until a

[14] SCAQMD, "Preliminary Draft Staff Report: Preliminary Draft Proposed Rule 1109.1", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pdsr_pr-1109-1_75_day.pdf?sfvrsn=6, page 3-10

[15] SCAQMD, "Preliminary Draft Staff Report: Preliminary Draft Proposed Rule 1109.1", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pdsr_pr-1109-1_75_day.pdf?sfvrsn=6, page 3-6

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Final Determination Notification is issued, it is unclear how a Facility is to address applicable limits that may be in effect for PR 1109.1. Relatedly, compliance with Rules 218.2 and 218.3 for CEMS is not required until a Facility becomes a Former RECLAIM Petroleum Refinery. For any limits in effect under PR 1109.1 at the Facility until it receives a Final Determination Notification, it is unclear if the Facility should follow a different set of CEMS requirements. MPC requests regulatory certainty to address the transition between RECLAIM and PR 1109.1 for compliance monitoring.

17. PR 1109.1 contains other clerical and administrative errors that need to be corrected.

Attachment 1 is a mark-up of PR 1109.1 with proposed changes as described in this letter and as follows:

- The rolling average times in Table 3 that are shown as "24-day" should be "24-hour."
- Capitalize words such as "Unit," "Petroleum Refinery," "Facility," etc., consistently throughout the rule to refer to the term defined in subdivision (c).
- Add in missing words for correct syntax.

Note that Attachment 1 of this letter is a conversion of the Adobe PDF version of PR 1109.1 into Microsoft Word, so the formatting of Attachment 1 is not as exact as shown in the August 20, 2021 version on SCAQMD's website.

For additional clarity, MPC recommends that SCAQMD add rule definitions for acronyms and shortened terms used in the rule such as "BARCT," "RECLAIM," and "O_2." MPC has not included proposed definitions for these terms in Attachment 1.

18. PR 1109.1 needs to reference and incorporate the startup and shutdown provisions in PR 429.1 and revise PR 429.1 so as to appropriately address management of startups and shutdowns.

The proposed PR 1109.1 rule does not reference PR 429.1 or otherwise clarify how startup and shutdown emissions are to be included or excluded for accounting against emission limits. Particularly, PR 1109.1 needs to expressly state that emissions from startups and shutdowns are exempt when determining compliance with the Alternative NOx BARCT Limits and the annual mass emissions against the BARCT Emissions Targets. To remove this ambiguity, MPC requests SCAQMD add a reference or statement in PR 1109.1 excluding the emissions from startup and shutdown events in PR 429.1 for purposes of compliance with emission limits in PR 1109.1.

Regarding the proposed PR 429.1 rule itself, MPC offers the following comments to address multiple startup and shutdown activities that are required for compliance with PR 1109.1. Attachment 2 of this letter is a proposed mark-up of PR 429.1 to reflect MPC's comments.

A. <u>Cogeneration unit electrical testing</u>

Cogeneration units are subject to industry and electrical standards to ensure that the equipment is reliable and in good working order. This includes conducting electrical testing following any upgrades or repairs made to the cogeneration unit's safety and control systems (e.g., protection relay and excitation control systems). These tests are to ensure that the systems have been functionally tested to prevent process safety and reliability issues. Some testing must take place at different electrical loads that can only occur during the startup phase. The testing duration ranges from 4 to 12 hours depending on the complexity of the

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testing. As this testing is to ensure the safety and reliability of the system, MPC requests that this testing be categorically excluded from the time limitations in paragraph (d)(2) of PR 429.1 by including the following:

- Add the following exemption as a new subparagraph (g)(1)(E) to paragraph (g)(1): *"electrical testing associated with commissioning of cogeneration control systems following upgrades or repairs."*; and

- Copy the definition of gas turbine from subdivision (c) of PR 1109.1, which incorporates the term "cogeneration."

B. <u>Catalyst maintenance and related activities</u>

MPC offers the following proposed changes to address catalyst maintenance and related activities:

- Paragraph (c)(2) requires that catalyst maintenance for a Unit *"... which has a bypass stack or duct ..."* MPC requests removal of this phrase, since some combustion units have only one stack which is used for both normal operations and for catalyst maintenance activities that bypass the control equipment (i.e., the control equipment is not operable during control equipment maintenance). Paragraph (d)(8) is also revised to align with this definition.

- The proposed definition in paragraph (c)(2) is specific only to catalyst maintenance activities and is not inclusive of other maintenance activities inherently needed for NOx post-combustion control equipment. For example, routine maintenance activities associated with a post-combustion control equipment's ammonia injection system and related components is required, which would impact emissions because ammonia is not being introduced into the control equipment during that time. MPC proposes to revise this definition to include maintenance of ancillary components in NOx post-combustion control equipment.

- Paragraph (d)(7) is an operating requirement for post-combustion control equipment if the temperature of the exhaust gas to the inlet of the control equipment *"... is greater than or equal to the minimum operating temperature."* Operating temperature fluctuates during startup, and MPC has observed from its operations that the minimum temperature may be initially reached for a very short duration and then fall below that minimum temperature before again rising to a minimum temperature until the stabilized minimum temperature is reached. For this reason, MPC requests that the aforementioned phrase be changed to *"... is greater than or equal to the minimum operating <u>and stable</u> temperature."*

- Subparagraph (d)(8)(D) requires documentation from a manufacturer of the *"minimum safe operating rate for the unit being bypassed."* The minimum safe operating rate for a Unit is a function of process safety management reviews by operations and safety staff and the application of MPC's operational safety policies and procedures to a Unit. Manufacturers will not know or have documentation of the minimum safe operating rate for a Unit. MPC requests deletion of this subparagraph.

C. <u>Gas turbines with NOx post-combustion control equipment</u>

Gas turbines with NOx post-combustion control equipment have issues that are similar to boilers and process heaters with respect to the necessary time allowance to meet NOx emission limits. MPC requests

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that Table 1 of PR 429.1 be changed such that a gas turbine with NOx post-combustion control equipment is subject to the same 48-hour time allowance as boiler and process heaters with NOx post-combustion control equipment.

D. Two-hour duration limit in Table 1 for process heaters

Based upon a review of its procedures and practices, MPC has determined that the startup and shutdown duration limit of two hours in Table 1 is insufficient for process heaters. It is unclear in the corresponding Draft Staff Report how this hourly limit was established. From MPC's experience it is unrealistic for several process heaters that do not have post-combustion NOx control equipment to reach stable conditions in two hours such that the NOx emissions controls (i.e., ultra-low NOx burners) can effectively meet the emission limits in PR 1109.1. For example, some heaters inherently require slower warming to avoid damaging downstream equipment affected by temperature changes and thus need more than 2 hours to start up. Also, heaters with natural draft systems or several dozen burners that need to be lit during startup will make control of excess oxygen difficult at low and fluctuating firing rates, which causes higher NOx concentrations until stable conditions are reached. To ensure MPC is allotted sufficient time to allow for safe and steady startup, MPC requests additional consultation with SCAQMD to support an appropriate increase to the 2-hour duration limit currently proposed in Table 1 for process heaters.

Please refer to the response to comments in the staff report for PR 1109.1

19. PR 1304 should further clarify in the rule language that BACT exemption is allowed for equipment replacements across categories of equipment.

MPC appreciates SCAQMD's consideration for including a limited exemption from BACT requirements for PM_{10} and SO_X emissions from projects that are implemented to comply with the PR 1109.1 requirements. This is important for allowing projects that will be completed for PR 1109.1 compliance to be permitted efficiently and implemented in a cost-effective manner. While the language in PR 1304(f)(1)(B) appears to allow for the exemption to apply to equipment to be replaced with other equipment across different source categories, there are some references in the associated PR 1304 Draft Staff Report indicating that equipment can only be replaced within the same source category (e.g., boilers replacing boilers).[16] For projects that involve replacement of equipment across source categories (e.g., boilers replacing co-generation units) that is functionally similar and does not increase the cumulative total maximum rated capacity, the rule language and staff report should be updated to reflect that the limited BACT exemption in PR 1304(f)(1) can be used. MPC has provided suggested rule language changes in Attachment 1 of this letter.

2-2~~1~~

20. PR 1304 (f)(1)(B) should allow for a longer period for replaced equipment to be operated at the same time consistent with federal requirements

Subparagraph (f)(1)(B) of PR 1304 currently states that *"For the new and/or modified permit unit(s) and the permit unit(s) being replaced, a maximum of 90 days is allowed as a startup period for simultaneous operation."* The length of time allowed for simultaneous operation of replacement units should be adjusted to align with the requirements of 40 CFR § 51.165(a)(1)(vi)(F) which allows a 180-day transition period for replacement units. This is a more appropriate time period when units are being replaced. PR 1304(f)(1)(B) should be adjusted to align with 40 CFR § 51.165(a)(1)(vi)(F).

2-3~~2~~

[16] SCAQMD, "Preliminary Draft Staff Report, Proposed Amended 1304 – Exemptions, Proposed Amended Rule 2005 – New Source Review for RECLAIM" http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/par-1304-and-par-2005/pdsr-par-1304_2005-aug-2021.pdf?sfvrsn=16 page 2-2

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Conclusion

MPC provides these comments to the Preliminary Draft Proposed Rule 1109.1 and related proposed and proposed amended rules issued August 20, 2021 to address critical deficiencies and needed clarifications.

Please note that in submitting this letter, MPC reserves the right to supplement its comments as it deems necessary, especially if additional or different information is made available to the public regarding the Proposed Rule 1109.1 rulemaking process.

Thank you for the opportunity to provide comments. We are glad to discuss further and look forward to continued dialogue.

Sincerely,

Bradley J Levi

Brad Levi
Vice President – Los Angeles Refinery

Attachments

cc: ***SCAQMD***
Sarah Rees – Deputy Executive Officer
Susan Nakamura – Assistant Deputy Executive Officer
Michael Krause – Planning and Rules Manager

cc: ***SCAQMD Governing Board***
Hon. Ben Benoit – Governing Board Chair
Hon. Lisa Bartlett – Governing Board Member
Hon. Joe Buscaino – Governing Board Member
Hon. Michael Cacciotti – Governing Board Member
Hon. Vanessa Delgado – Governing Board Vice-Chair
Hon. Gideon Kracov – Governing Board Member
Hon. Sheila Kuehl – Governing Board Member
Hon. Larry McCallon – Governing Board Member
Hon. Veronica Padilla-Campos – Governing Board Member
Hon. V. Manuel Perez – Governing Board Member
Hon. Rex Richardson – Governing Board Member
Hon. Carlos Rodriguez – Governing Board Member
Hon. Janice Rutherford – Governing Board Member

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ecc: 2021-09-17 MPC 75 Day Comment Letter on Revised Draft of SCAQMD PR 1109.1
Ruth Cade, MPC RE
Chris Drechsel, MPC RE
Denis Kurt, MPC LAR
Robert Nguyen, MPC LAR
Robin Schott, MPC LAR
Vanessa Vail, MPC LAW
Ben Franz, MPC LAW

Response to Comment 2-1

PAR 1304 includes a provision in subparagraph (f)(1)(E) specifying that it is permissible to use a mass balance engineering calculation to calculate emissions of PM for the purpose of determining federal major NSR applicability, which states:

> *"Notwithstanding any other South Coast AQMD rule, when calculating an emission increase for an installation of add-on air pollution control equipment with ammonia, a mass balance calculation may be used provided it employs the percent conversion of SO_2 to SO_3 found in the catalyst manufacturer specifications and uses fuel gas sulfur content representative of actual sulfur content."*

Staff revised the proposed rule language to clarify that nothing in Rule 1325 affects the methodology included in PAR 1304 subparagraph (f)(1)(E). Staff believes it is not necessary to incorporate a similar provision referencing the use of an acceptable calculation methodology in Rule 1325. The source testing methods referenced in Rule 1325 subdivision (h) – Test Methods are the methods that must be used if a source test is required. This reference to the source testing methods is not a requirement to conduct a source test.

Response to Comment 2-2~~1~~:

The PAR 1304 BACT exemption can be used for situations where a unit will be replaced with a new unit from a different source category. If the new unit is installed to meet the NOx BARCT limits and serves the same purpose, then the BACT exemption will not be restricted to require that the new unit be of the same category. Chapter 2 of this staff report further clarifies that if a unit is replaced with a unit from a different source category, the unit would be considered a new emission unit, rather than a replacement, under federal NSR. As a new emissions unit, federal major NSR applicability would be determined using a zero emissions baseline and the Actual-to-Potential test. If the unit treated as a new unit qualifies as a major modification, then it would not be able to use the BACT exemption in PAR 1304.

Response to Comment 2-3~~2~~:

The startup period allowed for a replacement under 40 CFR 51.165(a)(1)(vi)(F) is 180 days, provided it meets the definition of a replacement unit in 40 CFR 51.165(a)(1)(xxi). However, PAR 1304 subparagraph (f)(1)(B) limits simultaneous operation of new or modified permit unit(s) with the equipment being replaced to a maximum of 90 days to be consistent with the startup period allowed in division (d) of Rule 1313 – Permit to Operate.

COMMENT LETTER #3

WSPA

Patty Senecal
Senior Director, Southern California Region

October 6, 2021

Michael Morris
Manager, Planning and Rules
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Via e-mail at: mmorris@aqmd.gov

Re: WSPA Comments on Proposed Amended Rule 1304 and Proposed Amended Rule 2005

Dear Mr. Morris,

Western States Petroleum Association (WSPA) appreciates the opportunity to participate in the Working Group Meetings (WGMs) for South Coast Air Quality Management District (SCAQMD or District) Regional Clean Air Incentives Market (RECLAIM) Transition and Regulation XIII, New Source Review (NSR). These rulemakings are being undertaken to transition facilities in the RECLAIM program for NO_X emissions to a command-and-control structure (i.e., the "RECLAIM Transition Project"). WSPA is a non-profit trade association representing companies that explore for, produce, refine, transport, and market petroleum, petroleum products, natural gas, and other energy supplies in five western states including California. WSPA has been an active participant in air quality planning issues for over 30 years. WSPA-member companies operate petroleum refineries and other facilities in the South Coast Air Basin that are within the purview of the RECLAIM Program administered by the SCAQMD and will be impacted by the RECLAIM Transition Project.

We are writing to provide comments on the September 28, 2021, version of Proposed Amended Rule 1304 ("PAR 1304") and the August 20, 2021, version of Proposed Amended Rule 2005 ("PAR 2005") (collectively, the "Proposed Amendments"). WSPA previously submitted comments on the PAR 1304 Preliminary Draft Rule Language released on July 23, 2021.[1,2] WSPA supports the Proposed Amendments, and appreciates that PAR 1304 reflects some changes made in response to WSPA comments on earlier versions – particularly with respect to subdivisions (f)(1)(A) and (f)(1)(E). At this time, we do not have any specific comments regarding PAR 2005 and offer a limited number of recommendations that we believe would further improve PAR 1304.

As explained in the August 20, 2021, Preliminary Draft Staff Report for the Proposed Amendments ("Staff Report"), the Proposed Amendments will implement a narrow exemption from the requirement to install best available control technology ("BACT") for PM_{10} emission increases caused by the installation or modification of air pollution control equipment. The exemption addresses PM_{10} and SO_X emission increases associated with basic equipment replacements that are combined with the installation or

[1] Proposed Amended Rule 1304 Preliminary Draft Rule Language, Version 07-21-21. Available at: http://www4.aqmd.gov/enewsletterpro/uploadedimages/000001/PAR%201304%20Draft%20Rule%20Language%20July%202021.pdf. Accessed: September 2021.

[2] SCAQMD Regulation XIII, New Source Review: Proposed Amended Rule 1304 Exemptions. WSPA Comments on Proposed Rule Language, August 5, 2021. Available at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regx111/wspa-par1304-comment-letter-to-scaqmd-(final)-8-5-21.pdf?sfvrsn=6. Accessed: September 2021.

October, 5, 2021
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modification of air pollution control equipment for regulatory compliance. The best available retrofit control technology ("BARCT") rule, which includes Proposed Rule 1109.1 ("PR 1109.1), is required to transition the NO_X RECLAIM program to a command-and-control regulatory structure.

The Proposed Amendments are a critical underpinning of PR 1109.1. As explained in the Staff Report, installing a selective catalytic reduction ("SCR") system to achieve the PR 1109.1 NO_X limits will result in a PM_{10} emission increase that is greater than one pound per day, triggering BACT under Regulation XIII, which would require a sulfur treatment system to achieve a sulfur level of 30 ppm in refinery fuel gas, which could cost over $100 million to install.

This substantial cost was not included in the cost-effectiveness analysis conducted to determine the NOx BARCT emission limits in PR 1109.1. Nor is this cost taken into consideration in the socioeconomic analysis for PR 1109.1, and the potential environmental impacts of installing these controls are not addressed in the PR 1109.1 Supplemental Environmental Assessment prepared to comply with the California Environmental Quality Act. If the Proposed Amendments are not adopted and approved into the state implementation plan ("SIP") by the California Air Resources Board ("CARB") and U.S. Environmental Protection Agency ("USEPA"), ". . . then staff would need to look at a higher NOx concentration limit that is not based on SCR systems, and anticipated NOx reductions expected under PR 1109.1 would not come to fruition."[3]

Therefore, it is critical that the Proposed Amendments be adopted and submitted together with PR 1109.1 for approval by the United States Environmental Protection Agency (US EPA) and the California Air Resources Board (CARB) since the (future) availability of the PAR 1304 exemption is a key premise underlying the District's cost-effectiveness analysis for the District's PR 1109.1 NO_X BARCT determination. Our specific recommendations for PAR 1304 are set forth below.

1. **WSPA recommends that Staff consider future amendments to SCAQMD Rule 1325 and SCAQMD Regulation XVII to ensure consistency with PAR 1304.**

   In addition to SCAQMD Rule 1303, PM is regulated under two additional SCAQMD NSR programs – Rule 1325 and Regulation XVII, which implement Code of Federal Regulations Title 40 (40 CFR) Part 51 Section 165 and 40 CFR Part 52 Section 21, respectively.

   PAR 1304(f)(1)(E) specifies that the limited BACT exemption does not apply to a federal Major Stationary Source or Major Modification as defined in and determined pursuant to the identified federal programs and specifies the methodology for calculating an emission increase when making such determinations. When it undertakes further amendments to Regulation XIII to implement the RECLAIM Transition, staff should evaluate the need for any clarifying amendments to Rule 1325 and Regulation XVII related to implementation of subdivision (f)(1)(E). 3-1

2. **WSPA appreciates that staff has modified PAR 1304 (f)(1)(A) to make it clear that the BACT exemption applies to all BARCT compliance projects regardless of the specific emission limit to be achieved and recommends that staff also eliminate the date restriction.**

   PR 1109.1 includes a number of options for demonstrating compliance. Some of those options could include installing controls to reduce NOx emission, but not necessarily to the applicable BARCT level specified in the rule. The intent of the exemption is to apply to any project undertaken to demonstrate 3-2

[3] Proposed Amended Rule 1304 and Proposed Amended Rule 2005 Preliminary Draft Staff Report, August 2021, page 1-9. Available at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/par-1304-and-par-2005/pdsr-par-1304_2005-aug-2021.pdf?sfvrsn=16. Accessed: September 2021.

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compliance with the BARCT rule. In the case of PR 1109.1, that could be a project to achieve compliance with a Table 1 limit or a Table 2 limit, or some other limit in the context of a B-Plan or a B-Cap. WSPA previously expressed concerns about whether or not PAR 1304(f)(1) was clear on this point. We appreciate that Staff has deleted the word "specified" from the rule language and agreed to provide further clarification in the Staff Report.

Additionally, The District frequently amends the Source Specific Standards in Regulation XI. This PAR1304 limited BACT exemption should extend to associated increases in PM_{10} and/or SO_X emissions caused by the add-on air pollution control equipment resulting from future District-adopted BARCT rules, regardless of the date such a rule is adopted.

WSPA recommends that the language be further revised to:

(f)(1)(A) The new or modified permit unit(s) is located at a RECLAIM or former RECLAIM facility and is being installed or modified to comply with a South Coast AQMD rule to meet a NOx Best Available Retrofit Control Technology (BARCT) emission limit ~~established before December 31, 2023~~;

3-2 (Continued)

3. **The District should clarify that replacing units within different source categories can meet the requirement to "serve the same purpose."**

PAR 1304 (f)(1)(B) states that in order to qualify for the exemption, "the new and/or modified permit unit(s) will serve the same purpose as those being replaced and modified." In certain circumstances, a facility may choose to replace a unit with a unit in a different source category (e.g., replace a gas turbine with a boiler). The exemption should be available for such a project.

3-3

4. **The length of time allowed for simultaneous operation of replacement units should be adjusted to align with the requirements of 40 CFR 51.165 (a)(1)(vi)(F).**

PAR 1304 (f)(1)(B) states that "For the new and/or modified permit unit(s) and the permit unit(s) being replaced, a maximum of 90 days is allowed as a startup period for simultaneous operation." 40 CFR 51.165 (a)(1)(vi)(F) allows a 180-day transition period for replacement units. This is a more appropriate time period when units are being replaced. Rule 1304(f)(1)(B) should be adjusted to align with 40 CFR 51.165 (a)(1)(vi)(F).

3-4

5. **WSPA recommends clarifying changes to PAR 1304(f)(1)(C).**

PAR 1304 (f)(1)(C) states that in order to qualify for the exemption, the facility must "not have an increase in physical or operational design capacity, except for those changes needed for the new or modified permit unit(s) that meet the requirement of subparagraph (f)(1)(B)." The language should be modified to make it clear that the exemption will not cover facility improvements or upgrades which result in an increase in physical or design capacity that are ***not*** related to BARCT compliance. WSPA recommends that the language be revised to:

(f)(1)(C) ~~The facility does not have an increase in physical or operational design capacity, except for those~~ The changes needed for the new or modified permit unit(s) that meet the requirement of subparagraph (f)(1)(B) are the only changes allowed to have an increase in physical or operational design capacity at a RECLAIM or former RECLAIM facility. An increase in efficiency is not an increase in the physical and operational design capacity

3-5

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WSPA appreciates the opportunity to provide these comments related to PAR 1304. We look forward to continued discussion of this important rulemaking. If you have any questions, please contact me at (310) 808-2144 or via e-mail at psenecal@wspa.org.

Sincerely,

Patty Senecal

Cc: Wayne Nastri, SCAQMD
Susan Nakamura, SCAQMD
Cathy Reheis-Boyd, WSPA

Response to Comment 3-1:

Please see the response to Comment 2-1 regarding Rule 1325 and the implementation of PAR 1304 subparagraph (f)(1)(E).

Rule 1325 only applies to new Major Stationary Sources or Major Modifications at existing Major Stationary Sources for $PM_{2.5}$ or its precursors. Rule 1325 mirrors the federal requirements specified in 40 CFR 51.165, which include the definitions and procedures to determine if LAER is applicable to a Major Stationary Source or Major Modification. PAR 1304 subparagraph (f)(1)(E) specifies that the BACT exemption is only allowed for projects that are not subject to federal major NSR, which will be determined pursuant to the same federal major NSR provisions and definitions for a Major Stationary Source or Major Modification in 40 CFR 51.165. If a project constitutes a federal Major Stationary Source or Major Modification subject to Rule 1325, then the project would not qualify for the BACT exemption in PAR 1304.

Regulation XVII is implemented through a partial delegation of the federal major NSR provisions for the PSD program, which applies to Major Stationary Sources and Major Modification that emit Attainment Air Contaminants. A project that would qualify for the limited BACT exemption under PAR 1304 would not trigger federal PSD under 40 CFR 52.21 or Regulation XVII, since PAR 1304 subparagraph (f)(1)(E) does not allow the use of the BACT exemption if federal major NSR is triggered.

Amendments to Rule 1325 or Regulation XVII are not needed to implement PAR 1304 subparagraph (f)(1)(E), since the BACT exemption is limited to projects that would not trigger Rule 1325 and Regulation XVII. During the future amendments to Regulation XIII, staff may reevaluate if other NSR amendments are necessary and provide additional clarifications in Rule 1325.

Response to Comment 3-2

Please see the response to Comment 1-1 clarifying that the limited BACT exemption may be used for qualifying projects implemented to comply with a NOx BARCT rule, which includes projects to meet a Conditional NOx Concentration Limit or Alternative BARCT NOx Limit, such as a concentration NOx limit for a B-Plan or B-Cap.

Staff disagrees with the suggested revision to eliminate the date restriction. The BACT exemption is limited to rules where a NOx BARCT emission limit that was initially established before December 31, 2023 for the transition of facilities in the NOx RECLAIM program to a command-and-control regulatory structure. A revised NOx BARCT limit that was initially established before December 31, 2023 would be covered under this provision. Staff anticipates that all landing rules needed to transition facilities out of NOx RECLAIM will be completed before December 31, 2023. Any rules with new NOx BARCT limits after December 31, 2023 would primarily be for sources that are unrelated to the NOx RECLAIM transition. Although the cutoff date excludes future BARCT rules, NOx RECLAIM transition projects complying with a NOx BARCT limit that was initially established before December 31, 2023 and later revised would be able to use the BACT exemption. The limited BACT exemption cannot be extended to projects that are for regulatory compliance with future BARCT rules that are unrelated to the RECLAIM transition because it would result in an SB 288 issue. PAR 1304 does not interfere with SB 288 as when established, the RECLAIM transition was not envisioned. To ensure the BACT exemption will not be backsliding under SB 288, it is limited to implementation of emission reduction projects needed to transition facilities out of NOx RECLAIM to a command-and-control regulatory structure.

Response to Comment 3-3:

Please see the response to Comment 2-2.

Response to Comment 3-4

Please see the response to Comment 2-3.

Response to Comment 3-5:

Staff believes that the criteria specified in PAR 1304 subparagraph (f)(1)(C) as currently written expresses the intent clearly. PAR 1304 subparagraph (f)(1)(B) requires that there be no increase in the cumulative total maximum rated capacity for the new or modified permit unit(s) and PAR 1304 subparagraph (f)(1)(C) requires that there be no increase in the physical or operational design capacity for the entire facility, where an efficiency change is not considered an increase in the physical or operational design capacity. Excluding projects that would result in an increase in the cumulative total maximum rated capacity of a new or modified permit unit(s) and that are not related to air pollution control projects for NOx BARCT compliance, such as those that are solely for facility modernization or expansion, is necessary to ensure that the proposed narrow BACT exemption would not be backsliding under SB 288.

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Socioeconomic Impact Assessment For
Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations
Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations
Proposed Amended Rule 1304 – Exemptions
Proposed Amended Rule 2005 – New Source Review for RECLAIM

November 2021

Deputy Executive Officer
Planning, Rule Development & Area Sources
Sarah L. Rees, Ph.D.

Assistant Deputy Executive Officer
Planning, Rule Development, and Area Sources
Ian MacMillan

Author: Ryan Finseth, Ph.D. – Air Quality Specialist

Technical Assistance: Sarady Ka – Air Quality Specialist
Zoya Banan, Ph.D. – Air Quality Specialist
Mojtaba Moghani, Ph.D. – Air Quality Specialist
Heather Farr – Program Supervisor
Kevin Ni – Air Quality Specialist
Barbara Radlein – Program Supervisor
Sang-Mi Lee, Ph.D. – Program Supervisor
Paul Stroik, Ph.D. – Air Quality Specialist
Brian Vlasich - Air Quality Specialist

Reviewed By: Shah Dabirian, Ph.D. – Program Supervisor
Elaine Shen, Ph.D. – Acting Planning and Rules Manager
Mike Krause – Planning and Rules Manager
Susan Nakamura – Assistant Deputy Executive Officer
William Wong – Principal Deputy District Counsel
Barbara Baird – Chief Deputy Counsel

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
GOVERNING BOARD

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EXECUTIVE SUMMARY

A socioeconomic analysis has been conducted to assess the impacts of Proposed Rule 1109.1, Proposed Rule 429.1, and Proposed Amended Rules 1304 and 2005. The same level of analysis has also been performed on the California Environmental Quality Act (CEQA) alternatives. A summary of the analysis and findings are presented below.

Key Elements of the Proposed Amendments	Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR 1109.1) will facilitate the transition of petroleum refineries and facilities with related operations to petroleum refineries to a command-and-control regulatory structure and partially implement Control Measure CMB-05 of the 2016 Air Quality Management Plan (AQMP). PR 1109.1 applies to oxides of nitrogen (NOx) emitting combustion equipment at facilities, including asphalt plants, biofuel plants, hydrogen production plants, petroleum refineries, facilities that operate petroleum coke calciners, sulfuric acid plants, and sulfur recovery plants. The proposed rule will establish NOx and Carbon Monoxide (CO) emission limits to reflect the Best Available Retrofit Control Technologies (BARCT) for most combustion equipment categories at these facilities. Additionally, PR 1109.1 establishes provisions for monitoring, recordkeeping, and reporting and provides alternative implementation and compliance approaches including an Implementation Plan (I-Plan), BARCT Equivalent Compliance Plan (B-Plan), and BARCT Equivalent Mass Cap Plan (B-Cap), which provides flexibility and opportunities for facilities to reduce cost impacts. Proposed Rule 429.1 - Startup and Shutdown Provisions at Petroleum Refineries and Related Operations (PR 429.1) exempts units from PR 1109.1 NOx and CO emission limits and applicable rolling average provisions during startup, shutdown, and catalyst maintenance events. PR 429.1 also establishes requirements during startup and shutdown pursuant to U.S. EPA policies to regulate startup, shutdown, and malfunction. PR 429.1 limits the duration of startup and shutdown events and the frequency of scheduled startups. Additionally, PR 429.1 establishes best management practices for startup and shutdown events and notification and recordkeeping requirements. The provisions in PR 429.1 are not expected to impose additional costs to facilities, nor are they expected to result in additional emission reductions. As such, no adverse socioeconomic impacts are anticipated. Proposed amendments for Rule 1304 – Exemptions (Rule 1304) and Rule 2005 – New Source Review for RECLAIM (Rule 2005) are necessary to implement a narrow Best Available Control Technology (BACT) exemption. The exemption will allow for emission increases associated with air pollution control equipment installed for regulatory compliance with a Best Available Retrofit Control Technology

	(BARCT) rule required to transition the RECLAIM program for NOx to a command-and-control regulatory structure. The provisions in Rule 1304 and Rule 2005 are not expected to impose additional costs to facilities, nor are they expected to result in additional emission reductions. As such, no adverse socioeconomic impacts are anticipated.
Affected Facilities and Industries	PR 1109.1 will affect 16 facilities, including nine petroleum refineries, three small refineries, and four facilities with related operations. The three small refineries consist of two asphalt refineries and one biodiesel refinery, and the four facilities with related operations include three hydrogen plants and one sulfuric acid plant. Eleven of the 16 facilities are classified under NAICS 324 – Petroleum and Coal Products Manufacturing, four facilities are classified under NAICS 3251 – Basic Chemical Manufacturing, and the remaining facility is classified as NAICS 3259 – Other Chemical Product and Preparation Manufacturing. All 16 affected facilities are located in Los Angeles County. PR 1109.1 applies to nearly all combustion equipment at petroleum refineries and related facilities. Based on South Coast AQMD's permit database and facility surveys, staff has identified 292 units that will be subject to the PR 1109.1, with six major classes of equipment: process heaters & boilers (including steam methane (SMR) heater), gas turbines, fluid catalytic cracking units (FCCU), sulfur recovery unit/tail gas (SRU/TG) incinerators, vapor incinerators, and coke calciners. Across the 16 affected facilities there are 224 process heaters & boilers, 19 SRU/TG incinerators, 13 vapor incinerators, 12 gas turbines, 5 FCCUs, and 1 coke calciner.
Assumptions for the Analysis	PR 1109.1 is expected to result in approximately 7 to 8 tons per day (tpd) of NOx emission reductions from the installation and operation of control technology in order to comply with the lower NOx limits of PR 1109.1. For the sake of this analysis, however, a NOx emission reduction of 7.83 tpd was assumed. The 7.83 tpd emission reduction estimate represents staff's assumption regarding the units that would qualify to meet the Table 2 conditional limits with all other units meeting the Table 1 emission limits. The 7 – 8 tpd emission reduction range represents the range of emission reductions the rule will achieve considering the flexibility in the compliance options, the potential eligibility of the conditional limits for units not identified by staff, and the added emission reduction from the ten percent environmental benefit under the B-Cap approach. Compliance with the NOx limits in the proposed rule may overlap with projects currently taking place to comply with the 2015 NOx RECLAIM shave. This is due to 2017 emissions being used as baseline for the BARCT analysis in this proposed project, and those emissions could have since been reduced if a RECLAIM shave project has taken place since 2017.

	The proposed project is expected to achieve NOx emission reductions for every class and category of equipment and staff anticipates that 74 units will be retrofitted with new Selective Catalytic Reduction (SCR) Systems, 15 existing SCRs will be upgraded (SCR upgrade), and 76 units will be retrofitted with Ultra Low-NOx Burner (ULNB) technology. An assumed implementation schedule was developed which would comply with the emission reduction targets and schedule outlined in Table 4 of the proposed rule. The actual implementation of control equipment is uncertain and will likely differ from the schedule described here as affected facilities have been given flexibility in regards to which units will be required to meet the percent reductions specified in their approved implementation plan (I-Plan) to meet proposed BARCT emission limits. The analysis assumes that all capital costs (equipment and installation) are incurred in the year prior to implementation. Additionally, all recurring costs (O&M) and emission reductions begin in the implementation year assumed. The annualization factor used for capital costs is based on a real interest rate of 1% or 4% and a 25-year equipment life was assumed for all control equipment. All dollar figures are presented in 2018 dollars.
Cost Impacts	South Coast AQMD solicited direct input from affected facilities on the expected total installed costs and operating and maintenance (O&M) costs of all potential pollution control equipment necessary to implement BARCT. In 2018, South Coast AQMD staff received cost estimates from affected facilities that included 49 total installed cost (TIC) estimates that were obtained from 7 refineries for SCR retrofit and upgrade projects on heaters and boilers > 40 MMBtu/h. In 2021 affected facilities provided additional or revised cost estimates that included a total of 108 TIC estimates. Subsequently, Norton Engineering Consultants, Inc. provided an independent review of the facility provided cost data. Norton's conclusion was that the costs provided by the facilities are not unreasonable, considering the potential complexity. Staff assumed all SCR and ULNB costs received from facilities included capital, engineering, construction, tax, and shipping. In addition, all cost was assumed to include increased labor costs associated with Senate Bill (SB) 54 which requires refineries to use unionized construction labor. TIC provided were in different years and staff conservatively escalated all costs at 4% annual inflation rate to the 2018 dollar year. In addition, staff modified the U.S. EPA SCR cost spreadsheet using actual TIC estimates provided by the facilities to reflect the actual TIC

of SCR installations in the refinery sector. Cost assumptions were discussed extensively at multiple working group meetings and staff consulted with U.S. EPA Air Economics Group regarding staff's proposed methodology for revision of the SCR cost spreadsheet. Staff's revised methodology was approved and endorsed to reflect the change for the refinery sector. For ULNB TCI, staff used facility-submitted costs to fit a cost curve based on heat input (MMBtu/hr).

For the purpose of this analysis, facility-submitted costs are used when available. When facility submitted costs for a unit are unavailable, cost estimates generated from the SCR and ULNB cost curves based on the specific unit's heat input (MMBtu/hr) were used.

The table below includes the net present value (NPV) of capital, O&M, and total costs by equipment category based on a 4% discount rate. Total discounted costs are estimated to be $2.36 billion.

Total Discounted Costs by Equipment Category (4% Discount Rate)

Equipment Category	Capital (2018$ Millions)	O&M (2018$ Millions)	Total (2018$ Millions)
Boiler	$182.8	$28.7	$211.5
Coke Calciner	$39.1	$6.4	$45.5
FCCU	$61.5	$3.6	$65.2
Gas Turbine	$49.1	$5.3	$54.5
Heater	$1,649.2	$231.5	$1,880.6
SMR Heater	$63.2	$7.1	$70.3
SRU/TG	$26.7	$0.3	$26.9
Vapor Incinerator	$9.0	$0.2	$9.2
Total	**$2,080.5**	**$283.1**	**$2,363.6**

The table below includes the annual average of capital, O&M, and total costs by equipment category assuming capital costs are annualized using a 4% real interest rate. It is expected that average annual equipment costs will be $133.88 million on average.

Average Annual Cost by Equipment Category (4% real interest rate)

Equipment Category	Capital (2018$ Millions)	O&M (2018$ Millions)	Total (2018$ Millions)
Boiler	$9.81	$1.51	$11.32
Coke Calciner	$1.96	$0.32	$2.27
FCCU	$3.47	$0.19	$3.66
Gas Turbine	$2.38	$0.28	$2.66
Heater	$95.40	$13.05	$108.45
SMR Heater	$3.06	$0.34	$3.40
SRU/TG	$1.58	$0.02	$1.60
Vapor Incinerator	$0.52	$0.01	$0.53
Total	**$118.18**	**$15.70**	**$133.88**

Facilities installing new pollution control equipment will also incur additional administrative costs, such as compliance plan submission and permitting fees. Twelve facilities are expected to submit compliance plans. Plan submission fees are one-time costs billed at an hourly rate of $211.24 per hour and it is assumed that review of each compliance plan will require 120 hours of staff time. Affected facilities are also expected to incur one-time permitting costs due to permit processing for SCR applications ($6,104.08 per unit), change of condition to heater/boiler equipment permits ($8,308.45 per unit), processing fee for new burner heater/boiler equipment permits ($9,685.81 per unit), and Title V permit revisions ($2,853.99 per unit). Additionally, facilities installing new SCRs will incur annual permitting costs of $1,975.52 per unit per year.

Due to the large emission reductions projected from implementation of PR 1109.1, it is expected that affected facilities will incur a cost savings from reduced emission fees. Estimated cost savings were calculated using the estimated annual NOx emission reductions and assuming costs of $836.23 per ton of NOx for those facilities emitting more than 75 tons per year and $349.55 per ton of NOx for those facilities emitting more than 4 tons but less than 25 tons per year. Facilities' total cost savings due to NOx emission reductions are expected to reach $2.38 million per year upon full implementation.

Total discounted costs are expected to range from $2.336 billion to $2.920 billion based on 4% and 1% discount rates, respectively, and the average annual total costs of PR 1109.1 is expected to range from $98.10 million to $132.45 million per year based on the 1% and 4% real interest rate, respectively.

Total Compliance Costs

Cost Category	NPV (2018$ Millions)		Average Annual (2022 - 2057) (2018$ Millions)	
	1%	4%	1%	4%
Capital Costs	$2,494.02	$2,080.54	$83.83	$118.18
O&M Costs	$469.96	$283.11	$15.70	$15.70
Administrative Costs	$6.69	$4.96	$0.22	$0.22
Emissions Fees	-$50.63	-$32.36	-$1.66	-$1.66
Total	**$2,920.03**	**$2,336.24**	**$98.10**	**$132.45**

Job Impacts

Direct effects of the proposed project are used as inputs to the REMI model in order for the model to assess secondary and induced impacts for all the industries in the four-county economy on an annual basis and across a user-defined horizon: 2022 (first year assumed for the facilities to incur compliance costs due to BARCT implementation) to 2057 (last year cost associated with equipment installation are incurred). Direct effects of the proposed amendments include: (1) additional costs (net of emissions fee savings) to the 16 facilities that would install control equipment, (2) additional sales by local vendors of equipment, devices, or services that would meet the proposed requirements, and (3) increased fuel costs to all industries and consumers in the region.

Whereas all the compliance expenditures that are incurred by the affected facilities would increase their cost of doing business, the purchase of additional control equipment such as SCR, ULNB, and equipment installation would increase the spending and sales of businesses in various sectors, some of which may be located in the South Coast AQMD region.

The impact analysis assumes that facilities will pass on a percentage of their compliance costs onto consumers and local industries through an increase in the regional price of gasoline. Based on the report included in Appendix A, "The Impact of Proposed Rule 1109.1 on Fuel Prices and Demand in South Coast AQMD Region", it is assumed that 30% of total annual O&M costs, net of cost savings due to reduced emission fees, is passed on to consumers and industries through increased gasoline prices. The average annual increase in the price of gasoline is estimated to be 0.0035 cents per gallon. For added context, if 100% of all costs (capital and O&M) were passed on to consumers, it is projected that gasoline prices will increase by 0.99 cents per gallon (a 0.26% increase) on average, with a maximum expected increase of 1.42 cents per gallon (a 0.40% increase).

	Gas prices are expected to slowly increase as control equipment is installed over time. A maximum percentage increase of 0.014% is reached in 2033 upon full implementation of the rule. After 2033, price increases are expected to steadily decline as O&M costs remain constant and gas price projections steadily rise. When the compliance cost is annualized using a 4% real interest rate, it is projected that an annual average of 213 net jobs could be created annually from 2022 to 2057. The projected job impact becomes slightly more positive when the compliance cost annualized at a 1% interest rate is used. In earlier years of the implementation, the positive job impacts from the compliance expenditures made by affected facilities would more than offset the jobs forgone from the additional cost of doing business. From 2022-2032, it is projected that an average of 1,837 jobs would be added annually. In 2032, when most of the spending is expected to occur, about 4,435 additional jobs are projected in the regional economy. The positive job impact would trickle down to the sectors of construction, miscellaneous professional services, retail & wholesale trade, food services, and real estate. However, as affected facilities continue to incur the amortized capital expenditures and annual O&M costs, reductions in job growth would set in, resulting in jobs forgone in later years. Despite incurring the majority of the total compliance cost, the petroleum and coal products manufacturing industry (NAICS 324) is projected to experience only minor impacts in terms of jobs forgone (14 on average). This is due to the fact that the industry is capital-intensive. As such, less labor would be required to produce the same amount of products or services.
Impact of CEQA Alternatives	Four alternatives to the proposed project were developed for the CEQA analysis associated with this proposal, Alternative A - No Project, Alternative B - More Stringent, Alternative C - Less Stringent, and Alternative D - Limited Start-Up, Shutdown, Malfunction. This section provides a description of each alternative as well as an assessment of the possible socioeconomic impacts resulting from these alternatives. Alternatives A and D have identical NPV of compliance costs, job impacts, and cost-effectiveness to the proposed project given the modeling assumptions employed. Alternative B has a higher NPV of compliance costs given the expedited implementation schedule for small heaters and boilers, resulting in more of the compliance costs to occur in earlier periods. Alternative C has a lower NPV of compliance costs due to the assumption of an extended implementation schedule for all units, thus allowing for compliance costs to occur in later periods.
Public Health Benefits	The South Coast Air Basin is one of only two “extreme” non-attainment areas in the nation that have not reached the federal 8-hour ozone

	standard. In addition, the South Coast Air Basin remains a non-attainment area for the federal PM2.5 standards. According to recent estimates by the California Air Resources Board, elevated ambient PM2.5 levels result in approximately 4,100 premature deaths annually in the South Coast Air Basin. The reductions in ozone and PM2.5 associated with the proposed rule have the potential to reduce the mortality and morbidity incidences associated with NOx emissions. Public health benefits resulting from compliance with PR 1109.1 are calculated using an incidence per ton (IPT) methodology, developed by the U.S. Environmental Protection Agency. The IPT methodology is an approximation based on the assumption that the relationship between emissions and adverse health outcomes is linear. The public health benefits analysis presented is based on the proposed project which assumes 74 new SCRs, 15 SCR upgrades, and 76 ULNBs will be installed as a result of 1109.1. PR 1109.1 is projected to result in a reduction in NOx emissions of 7 to 8 tpd upon full implementation; however, for the sake of the health benefit analysis, 7 tpd was conservatively assumed. The increased use of ammonia associated with the SCR controls creates the potential for ammonia slip. It is expected that the installation of 74 new SCRs will result in a 0.63 tpd increase in ammonia emissions. Ammonia is also a precursor to PM2.5. Using IPT methodology, decreases in NOx emissions will result in positive health benefits (reductions in mortality and morbidity resulting from decreased ambient PM2.5 concentrations), while concurrent increases in NH3 will result in increases in mortality and morbidity. Projected reductions of NOx are much larger than the expected increase in NH3, resulting in a net benefit to the South Coast Air Basin. Emissions changes are expected to cumulatively result in approximately 370 premature mortalities avoided from long-term and short-term PM2.5 exposure. Additionally, it is expected that PR 1109.1 will result in approximately 6,200 fewer asthma attacks and nearly 21,400 fewer work loss days over the course of the time period from 2023-2037. The discounted total monetized public health benefits over the 15-year time period is projected to be \$3.49 billion using a 1% discount rate and \$2.63 billion using a 4% discount rate. Total discounted public health benefits were calculated over a shorter time period (2022-2037 for health benefits vs 2022-2057 for compliance costs), therefore the NPV for monetized health benefits cannot be directly compared to the NPV of compliance costs, but even so, monetized health benefits exceed total costs.

INTRODUCTION

Proposed Rule 1109.1

Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR 1109.1) will facilitate the transition of petroleum refineries and facilities with related operations to petroleum refineries from the current RECLAIM program to a command-and-control regulatory structure and partially implement Control Measure CMB-05 of the 2016 Air Quality Management Plan (AQMP). PR 1109.1 applies to oxides of nitrogen (NOx) emitting combustion equipment at facilities, including asphalt plants, biofuel plants, hydrogen production plants, petroleum refineries, and facilities that operate petroleum coke calciners, sulfuric acid plants, and sulfur recovery plants. The proposed rule will establish NOx and carbon monoxide (CO) emission limits to reflect BARCT for combustion equipment categories at these facilities. Additionally, PR 1109.1 establishes provisions for monitoring, recordkeeping, and reporting and provides alternative implementation and compliance approaches including an Implementation Plan (I-Plan), BARCT Equivalent Compliance Plan (B-Plan), and BARCT Equivalent Mass Cap Plan (B-Cap) which provides flexibility and opportunities for facilities to reduce cost impacts while achieving equivalent emission reductions.

Proposed Rule 429.1

Proposed Rule 429.1 - Startup and Shutdown Provisions at Petroleum Refineries and Related Operations (PR 429.1) exempts units from PR 1109.1 NOx and CO emission limits and applicable rolling average provisions during startup, shutdown, and catalyst maintenance events. PR 429.1 also establishes requirements during startup and shutdown pursuant to U.S. EPA policies to regulate startup, shutdown, and malfunction. PR 429.1 limits the duration of startup and shutdown events and the frequency of scheduled startups. Additionally, PR 429.1 establishes best management practices for startup and shutdown events and notification and recordkeeping requirements. The provisions in PR 429.1 are not expected to impose additional costs to facilities, nor are they expected to result in additional emission reductions. As such, no adverse socioeconomic impacts are anticipated.

Proposed Amended Rules 1304 and 2005

Proposed amendments for Rule 1304 – Exemptions (Rule 1304) and Rule 2005 – New Source Review for RECLAIM (Rule 2005) are necessary to implement a narrow Best Available Control Technology (BACT) exemption. The exemption will allow for emission increases associated with air pollution control equipment installed for regulatory compliance with a Best Available Retrofit Control Technology (BARCT) rule required to transition the RECLAIM program for NOx to a command-and-control regulatory structure. Rule 1304 and Rule 2005 are not expected to impose additional costs to facilities, nor are they expected to result in additional emission reductions. As such, no adverse socioeconomic impacts are anticipated.

REGULATORY HISTORY

Rule 1109

On November 1, 1985, South Coast AQMD adopted Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries. The rule was subsequently amended on August 5, 1988. Rule 1109 was applicable to all boilers and process heaters in petroleum refineries and established a NOx refinery-wide emission limit of 0.14 lb/MMBtu (approximately 120 ppm NOx corrected to three percent oxygen) for the units operated on gaseous fuel, 0.308 lb/MMBtu (approximately 250 ppm NOx corrected to three percent oxygen) for the units operated on liquid fuel, and the weighted average of these limits for the units operated concurrently on both liquid and gaseous fuels when the units are firing at the maximum rated capacity.

RECLAIM

The South Coast AQMD Governing Board adopted the Regional Clean Air Incentives Market (RECLAIM) program in October 1993. The purpose of RECLAIM was to reduce NOx and Sulfur Oxides (SOx) emissions through a market-based approach for facilities with NOx or SOx emissions greater or equal to four tons per year. The program replaced a series of existing and future command-and-control rules and was designed to provide facilities with the compliance flexibility. RECLAIM was designed to achieve emission reductions in aggregate equivalent to what would occur under a command-and-control regulatory approach. Regulation XX – RECLAIM includes a series of rules that specify the applicability and procedures for determining NOx and SOx facility emissions allocations, program requirements, as well as monitoring, reporting, and recordkeeping requirements for RECLAIM facilities. When RECLAIM was adopted, all petroleum refineries and facilities with operations related to petroleum facilities (related facilities) transitioned to this market-based program.[1]

Pursuant to Health & Safety Code §40440, South Coast AQMD is required to periodically assess the advancement in control technologies that are representative of BARCT to ensure that RECLAIM facilities achieve the same emission reductions that would have occurred under a command-and-control approach and that RECLAIM sources contribute to the efforts in the Basin to achieve the federal National Ambient Air Quality Standards (NAAQS). Over the course of RECLAIM, there have been two BARCT reassessment for NOx in 2005 and 2015.

In 2005, Regulation XX was amended to achieve additional NOx reductions pursuant to the 2003 AQMP Control Measure CMB-10. The NOx RTC shave target for the 2005 amendments was 7.7 tons per day (tpd) from 2007 to 2011. The actual NOx emission reductions between the timeframe

[1] A socioeconomic analysis of RECLAIM was conducted at the time of its adoption. The cost of RECLAIM was estimated to be $80.8 million annually, on average, compared with the $138.7 million cost of the corresponding command-and-control system (which included rules and control measures in the 1991 AQMP that were subsumed by RECLAIM). RECLAIM was predicted to result in an average of 866 jobs forgone annually, compared with 2,013 jobs forgone under the command-and-control system. Based on the five occupational categories from the lowest-paid to the highest-paid, RECLAIM was projected to result in increased employment opportunities for nearly every category relative to the command-and-control system.

of 2006 and 2012 was 4 tpd. Of these 4 tpd, 2.6 tpd (or 65%) originated from facility shutdowns, while 1.4 tpd (or 35%) came from either emission controls, process changes, and/or from decreases in production levels. The proposed amendments also addressed requirements for demonstrating BARCT equivalency in accordance with H&SC §40440. In addition, trading restrictions for electricity generating producing facilities were removed.

On December 4, 2015, Regulation XX was again amended to reduce NOx allocations for the largest NOx emitters by 12 tpd. Refineries and related industries represented approximately 7.9 tpd (66%) of the 12 tpd. The intent of the BARCT reassessments was to ensure the RECLAIM program achieved the BARCT in aggregate. Additionally, it was estimated that the refinery sector would incur average annual costs of $51.3 million from 2018-2035 as a result of the shave. However, recent evaluation of the units at petroleum refineries and related industries indicate 88% of the equipment at those facilities are not operating at levels representative of BARCT. And as of August 2021, only nine permits have been submitted from petroleum refineries and related industries for large NOx reduction projects, compared to the 91 SCR projects assumed to be needed to achieve the 2015 NOx shave.

On January 5, 2018, the Governing Board adopted amendments to Rule 2001 – Applicability and Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx). Amendments to Rule 2001 ended the addition of any facilities into RECLAIM, and Rule 2002 included provisions to establish the overall process to transition facilities from the RECLAIM program to a command-and-control regulatory structure. Before a facility can be transitioned out of RECLAIM, the facility must either have all equipment at BARCT or be subject to a rule that establishes BARCT requirements for their equipment. As a result, it is expected that as applicable source-specific or industry-specific BARCT rules are adopted or amended, staff can initiate the transition process for facilities subject to those rules.

LEGISLATIVE MANDATES

The legal mandates directly related to the assessment of the proposed rule include South Coast AQMD Governing Board resolutions and various sections of the California Health & Safety Code.

South Coast AQMD Governing Board Resolutions

On March 17, 1989 the South Coast AQMD Governing Board adopted a resolution that calls for an economic analysis of regulatory impacts that includes the following elements:

- Affected industries
- Range of probable costs
- Cost-effectiveness of control alternatives
- Public health benefits

Health and Safety Code Requirements

The state legislature adopted legislation which reinforces and expands the Governing Board resolutions for socioeconomic impact assessments. California Health and Safety Code section

40440.8, which became effective on January 1, 1991, requires a socioeconomic impact assessment be performed for any proposed rule, rule amendment, or rule repeal which "will significantly affect air quality or emissions limitations."

Specifically, the scope of the socioeconomic impact assessment should include the following:

- Type of affected industries;
- Impact on employment and the regional economy;
- Range of probable costs, including those to industry;
- Availability and cost-effectiveness of alternatives to the rule;
- Emission reduction potential; and
- Necessity of adopting, amending, or repealing the rule in order to attain state and federal ambient air quality standards.

Health and Safety Code section 40728.5, which became effective on January 1, 1992, requires the South Coast AQMD Governing Board to actively consider the socioeconomic impacts of regulations and make a good faith effort to minimize adverse socioeconomic impacts. It also expands socioeconomic impact assessments to include small business impacts, specifically it includes the following:

- Type of industries or business affected, including small businesses; and
- Range of probable costs, including costs to industry or business, including small business.

Finally, Health and Safety Code section 40920.6, which became effective on January 1, 1996, requires incremental cost-effectiveness be performed for a proposed rule or amendment which imposes Best Available Retrofit Control Technology or “all feasible measures” requirements relating to ozone, CO, SOx, NOx, and their precursors.

AFFECTED FACILITIES

PR 1109.1 will affect 16 facilities, including nine petroleum refineries, three small refineries, and four facilities with related operations. The three small refineries consist of two asphalt refineries and one biodiesel refinery, and the four facilities with related operations include three hydrogen plants and one sulfuric acid plant. Eleven of the 16 facilities are classified under NAICS 324 – Petroleum and Coal Products Manufacturing, four facilities are classified under NAICS 3251 – Basic Chemical Manufacturing, and the remaining facility is classified as NAICS 3259 – Other Chemical Product and Preparation Manufacturing. All 16 affected facilities are located in Los Angeles County.

PR 1109.1 applies to nearly all combustion equipment at petroleum refineries and related facilities. Based on South Coast AQMD’s permit database and facility surveys, staff has identified 292 units that will be subject to the PR 1109.1, with six major classes of equipment: process heaters & boilers (including steam methane (SMR) heater), gas turbines, fluid catalytic cracking units (FCCU), sulfur recovery unit/tail gas (SRU/TG) incinerators, vapor incinerators, and coke calciners. Across the 16 affected facilities there are 224 process heaters & boilers, 19 SRU/TG incinerators, 13 vapor incinerators, 12 gas turbines, 5 FCCUs, and 1 coke calciner.

Small Business

The South Coast AQMD defines a "small business" in Rule 102 for purposes of fees as one which employs 10 or fewer persons and which earns less than $500,000 in gross annual receipts. The South Coast AQMD also defines "small business" for the purpose of qualifying for access to services from the South Coast AQMD's Small Business Assistance Office (SBAO) as a business with an annual receipt of $5 million or less, or with 100 or fewer employees. In addition to the South Coast AQMD's definitions of a small business, the federal Small Business Administration (SBA) and the federal 1990 Clean Air Act Amendments (1990 CAAA) also provide definitions of a small business.

The 1990 CAAA classifies a business as a "small business stationary source" if it: (1) employs 100 or fewer employees, (2) does not emit more than 10 tons per year of either VOC or NOx, and (3) is a small business as defined by SBA. The SBA definitions of small businesses vary by six-digit NAICS codes. In general terms, a small business must have no more than 500 employees for most manufacturing and mining industries.[2] More specifically, the petroleum refineries sector (NAICS 324110) has 1,500 employees as the threshold below which a business is considered small. Additionally, the industrial gas manufacturing sector (NAICS 325120) has a small business threshold of 1,000 employees.

Publicly available data on the number of employees by facility exists for all 16 affected facilities. Additionally, 2021 Dun and Bradstreet data on revenue is available for all affected facilities. Based on this data, there are no affected facilities that meet the South Coast AQMD's definitions of a small business (both Rule 102 and SBAO). Based on SBA's definition of a small business, two small refinery facilities would be classified as a small business. Under the 1990 CAAA definition, there are no facilities meeting the criterion to be considered a small business.[3]

METHODOLOGY OF SOCIOECONOMIC IMPACT ASSESSMENT

PR 1109.1 is expected to result in approximately 7 to 8 tpd of NOx emission reductions from the installation and operation of control technology in order to comply with the lower NOx limits of PR 1109.1. For the sake of this analysis, however, a NOx emission reduction of 7.83 tpd was assumed.[4] The 7.83 tpd emission reduction estimate represents staff's assumption regarding the units that would qualify to meet the Table 2 conditional limits with all other units meeting the Table 1 emission limits.[5] The 7 – 8 tpd emission reduction range represents the range of emission

[2] https://www.sba.gov/sites/default/files/files/Size_Standards_Table.pdf
[3] Based on facility-level data on NOx and VOC emissions for calendar years 2018, 2019, and 2020.
[4] The 7.83 tpd projection does not include emission reductions from 67 small heaters and 5 small boilers (less than 40 MMBtu) expected to be retrofitted with emerging technology.
[5] The emission limits outlined in the proposed rule are the result of a BARCT assessment for combustion equipment located at all sixteen affected facilities (http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1_30_day-package.pdf).

reductions the rule will achieve considering the flexibility in the compliance options, the potential eligibility of the conditional limits for units not identified by staff, and the added emission reduction from the ten percent environmental benefit under the B-Cap approach.[6,7]

Compliance with the NOx limits in the proposed rule may overlap with projects currently taking place to comply with the 2015 NOx RECLAIM shave. This is due to 2017 emissions being used as baseline for the BARCT analysis in this proposed project, and those emissions could have since been reduced if a RECLAIM shave project has taken place since 2017.

The proposed project is expected to achieve NOx emission reductions for every class and category of equipment and staff anticipates that 74 units will be retrofitted with new Selective Catalytic Reduction (SCR) Systems, 15 existing SCRs will be upgraded (SCR upgrade), and 76 units will be retrofitted with Ultra Low-NOx Burner (ULNB) technology. Table 1 below presents the estimated number of new or upgraded pollution control equipment by equipment category.

Table 1: Estimated Number of NOx Control Devices by Equipment/Source Category

Equipment Category	Number of Affected Facilities	Estimated Number of Control Devices
Process Heaters	7	60 SCR
		49 ULNB
		6 SCR upgrade
Boilers	7	9 SCR
		10 ULNB
		2 SCR upgrade
FCCUs	2	2 SCR
Coke Calciner	1	1 SCR
Gas Turbines	2	5 SCR upgrade
SRU/TG	6	9 ULNB
SMR Heaters	4	2 SCR
		2 SCR upgrade
Vapor Incinerators	4	8 ULNB

Based on the control devices listed in Table 1, an assumed implementation schedule was developed which would comply with the emission reduction targets and schedule outlined in Table 4 of the proposed rule. The actual implementation of control equipment is uncertain and will likely differ from the schedule described here as affected facilities have been given flexibility in regards to which units will be required to meet the percent reductions specified in their approved

[6] For more information regarding the B-Cap approach, please see the most recent version of the Staff Report: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/dsr_pr_1109-1_30_day_package.pdf
[7] The 7.83 tpd in NOx reductions is a conservative estimate and represents a "high-cost" scenario.

implementation plan (I-Plan) to meet proposed BARCT emission limits. Table 2 below summarizes the assumed implementation schedule by equipment category.

This analysis assumes that all capital costs (equipment and installation) are incurred in the year prior to implementation. Additionally, all recurring costs (O&M) and emission reductions begin in the implementation year shown in Table 8. Table 3 below provides the projected emission reductions by year and equipment category.

South Coast AQMD received direct input from affected facilities on the expected total installed costs and operating and maintenance (O&M) costs of all potential pollution control equipment necessary to implement BARCT. In 2018 South Coast AQMD received cost estimates from affected facilities that included 49 total installed cost (TIC) estimates that were obtained from 7 refineries for SCR retrofit and upgrade projects on heaters and boilers > 40 MMBtu/h. In 2021, affected facilities provided additional or revised cost estimates that included a total of 108 additional or revised TIC estimates. Revised cost estimates for all but two units received in 2021 were 1.05 to 2.4 times greater than initial estimates. Subsequently, Norton Engineering Consultants, Inc. provided an independent review of the facility cost data to determine whether the costs submitted were reasonable, realistic, and justified for NOx control equipment installations. The independent review ultimately determined that the facility costs submitted "do not appear unreasonable."[8]

Staff assumed all SCR and ULNB costs received from facilities included capital, engineering, construction, tax, and shipping. In addition, all cost was assumed to include increased labor costs associated with Senate Bill (SB) 54 which requires refineries to use unionized construction labor. TIC provided were in different years and staff conservatively escalated all costs at 4% annual inflation rate to the 2018 dollar year.[9]

In addition, staff modified the U.S. EPA SCR cost spreadsheet using actual TIC estimates provided by the facilities to reflect the actual TIC of SCR installations in the refinery sector. Staff consulted with U.S. EPA Air Economics Group regarding staff's proposed methodology for revision of the SCR cost spreadsheet. Staff's revised methodology was approved and endorsed to reflect the change for the refinery sector. For ULNB TCI, staff used facility-submitted costs to fit a cost curve based on heat input (MMBtu/hr).

For the purpose of this analysis, facility-submitted costs are used when available. When facility submitted costs for a unit are unavailable, cost estimates generated from the SCR and ULNB cost curves based on the specific unit's heat input (MMBtu/hr) were used.

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[8] http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/norton-report-rev-2-barct-cost-review.pdf?sfvrsn=6

[9] The use of the 4% inflation factor is a conservative estimate, resulting in a higher cost estimate. For comparison, the average increase in the Consumer Price Index, or CPI, over the period from 2011 to 2020 is 1.73% (https://fred.stlouisfed.org/series/CPALTT01USA657N) and the average increase in the GDP deflator over the same time period is 1.7% (https://fred.stlouisfed.org/series/A191RI1A225NBEA). In addition, the average annual increase in the Marshall & Swift Cost Index is 1.6% over the time period 2011 to 2020.

Table 2: Assumed Installation Schedule by Equipment Category

Year	Boilers	FCCU	Coke Calciner	Gas Turbines	Process Heaters	SRU/TG	SMR Heaters	Vapor Incinerators
2023 (Shave Projects)	4 ULNB + 3 SCR + 1 SCR upgrade	1 SCR	-	3 SCR upgrade	8 ULNB + 8 SCR + 1 SCR upgrade	-	2 SCR	-
2024	-	-	-	-	5 ULNB + 7 SCR	1 ULNB	-	2 ULNB
2025	1 ULNB + 1 SCR	-	1 SCR	-	1 ULNB + 2 SCR + 1 SCR upgrade	-	1 SCR upgrade	-
2026	1 ULNB + 1 SCR	-	-	1 SCR upgrade	9 ULNB + 10 SCR	-	-	-
2027	1 ULNB + 1 SCR	-	-	-	4 ULNB + 7 SCR + 2 SCR upgrade	-	-	-
2028	1 ULNB + 1 SCR	-	-	1 SCR upgrade	6 ULNB + 7 SCR	3 ULNB	-	3 ULNB
2029	1 ULNB + 1 SCR	-	-	-	4 ULNB + 5 SCR + 1 SCR upgrade	-	-	-
2030	-	1 SCR	-	-	7 ULNB SCR + 6 SCR	-	-	-
2031	1 ULNB + 1 SCR	-	-	-	2 ULNB + 3 SCR	1 ULNB	1 SCR upgrade	2 ULNB
2032	1 SCR upgrade	-	-	-	1 ULNB + 2 SCR + 1 SCR upgrade	1 ULNB	-	1 LNB
2033	-	-	-	-	2 ULNB + 3 SCR	3 ULNB	-	-
Total	**10 ULNB + 9 SCR + 2 SCR upgrade**	**2 SCR**	**1 SCR**	**5 SCR upgrade**	**49 ULNB + 60 SCR + 6 SCR upgrade**	**9 ULNB**	**2 SCR + 2 SCR upgrade**	**8 ULNB**

Table 3: Projected NOx Emission Reductions Based on Assumed Installation Schedule by Equipment Category by Year (in tpd)

Year	Boilers	Coke Calciner	FCCU	Gas Turbines	Heaters	SMR Heaters	SRU/TG	Vapor Incinerators	Total
2023 (Shave Projects)	1.25	-	0.13	0.24	0.51	0.54	-	-	**2.68**
2024	-	-	-	-	0.60	-	-	0.01	**0.61**
2025	0.07	0.66	-	-	0.08	0.07	-	-	**0.89**
2026	0.10	-	-	0.11	0.67	-	-	-	**0.89**
2027	0.35	-	-	-	0.38	-	-	-	**0.72**
2028	0.02	-	-	0.11	0.30	-	0.06	0.01	**0.50**
2029	0.28	-	-	-	0.30	-	-	-	**0.58**
2030	-	-	0.22	-	0.24	-	-	-	**0.46**
2031	0.09	-	-	-	0.18	0.02	0.01	0.01	**0.29**
2032	0.04	-	-	-	0.05	-	0.01	-	**0.10**
2033	-	-	-	-	0.09	-	0.02	-	**0.11**
Total	**2.19**	**0.66**	**0.35**	**0.46**	**3.42**	**0.63**	**0.09**	**0.02**	**7.83**

COMPLIANCE COST BY EQUIPMENT CATEGORY

Fluid Catalytic Cracking Units (FCCU)

An FCCU converts heavy gas oils from the distillation process into more valuable gasoline and lighter products. Currently there are five refineries that operate five FCCUs in the South Coast Air Basin. The five units cumulatively emit a total of 0.83 tpd of NOx. For more information on FCCUs, including a detailed process description, assessment of available control technologies, and BARCT cost-effectiveness analysis, please see Appendix D of the most recent PR 1109.1 Staff Report.

There is one FCCU unit that is currently operating at the proposed BARCT limit. It is assumed that two FCCU units currently without NOx controls will install new SCRs, and two units with NOx controls will perform SCR upgrades.

The total compliance cost of the proposed amendments for refinery FCCUs includes one-time capital costs and recurring O&M costs. The one-time cost includes the capital cost of SCRs and their installations. The total installed cost of the 2 SCRs are estimated at $19.5 and $58.5 million, respectively. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. The annual O&M costs for the 2 SCR units include utility costs (electricity) and ammonia costs. The annual O&M cost for each SCR unit is estimated at $0.14 million. It is assumed that 30% of annual operating costs are attributed to utility costs and the remaining 70% to ammonia.

Assuming a 25-year life for equipment and installation,[10,11] and a discount rate of 4%, the net present value (NPV) of all capital costs is estimated at $61.53 million.[12,13] The NPV of all annual

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[10] Staff assumed a 25-year equipment life for SCRs to be installed based on the profiles of SCRs used by refineries in the Basin. In 2015, nearly 30 percent of the refinery combustion equipment in the Basin had SCRs that had been installed more than 25 years ago, and more than 60 percent of the refinery combustion equipment had SCRs that had been installed more than 20 years ago. At the time, these units were still in operation and thus support the assumption of a 25-year useful life in the cost analysis.

[11] Assuming a longer equipment life results in an increase in total costs due to additional O&M costs accrued over a longer period of time. However, the annualized cost would become lower due to a longer period to amortize the upfront capital cost.

[12] In 1987, SCAQMD staff began to calculate cost-effectiveness of control measures and rules using the Discounted Cash Flow method with a discount rate of 4 percent. Although not formally documented, the discount rate is based on the 1987 real interest rate on 10-year Treasury Notes and Bonds, which was 3.8 percent. The maturity of 10 years was chosen because a typical control equipment life is 10 years; however, a longer equipment life would not have corresponded to a much higher rate-- the 1987 real interest rate on 30-year Treasury Notes and Bonds was 4.4 percent. Since 1987, the 4 percent discount rate has been used by SCAQMD staff for all cost-effectiveness calculations, including BACT analysis, for the purpose of consistency. The compliance cost reported in this assessment was thus annualized using a real interest rate of 4 percent. As a sensitivity test, a real interest rate of 1 percent was also used, which is closer to the average real interest rate over the past five years, 0.1% (see https://fred.stlouisfed.org/series/DFII10).

[13] The high discount rate scenario (4%) results in a comparatively lower NPV than the low discount rate scenario (1%).

operating and maintenance costs is estimated to be $3.62 million. Table 4 presents detailed costs by refinery.

Table 4: FCCUs – Net Present Value of All Equipment, Installation, and Annual Operating Costs (Millions of 2018 Dollars)

Refinery	Equipment Cost	Installation Cost	Total O&M	Electricity/Water	Ammonia/Caustic	Catalyst	Other Maintenance
7	$3.750	$15.000	$2.058	$0.617	$0.823	$0.412	$0.206
9	$8.555	$34.220	$1.564	$0.469	$0.626	$0.313	$0.156
Total	**$12.305**	**$49.220**	**$3.622**	**$1.087**	**$1.449**	**$0.724**	**$0.362**

Process Heaters and Boilers

Refinery process heaters and boilers are used extensively throughout various processes in refinery operations such as distillation, hydrotreating, fluid catalytic cracking, alkylation, reforming, and delayed coking. The refinery heaters and boilers primarily burn refinery gas which is generated at the refinery. Most of these boilers and heaters use natural gas as back-up or supplemental fuel.

Process Heaters

Process heaters are direct-fired heaters designed to supply the heat necessary to raise the temperature of feedstock to the distillation or reaction levels. There are 185 heaters currently in operation at affected facilities within the South Coast Air Basin. These units cumulatively emitted 5.03 tpd of NOx in 2017.

For the purpose of the analysis, controlling NOx emissions from process heaters is assumed to be accomplished through SCR upgrades, the installation of SCR, and/or installation of ULNB. It is assumed that seven refineries would install 15 SCR units only, while three refineries will perform four SCR upgrades only. It is also assumed that three refineries will install three ULNBs only. Additionally, it is assumed that seven refineries will install 45 SCR + ULNBs and two refineries will install a new ULNB and perform an upgrade to an existing SCR. In total, there will be 60 new SCRs installed, six SCR upgrades performed, and 49 new ULNBs installed to existing process heaters.

The estimated TIC of new SCR installations range from $12.4 million to $70.0 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs resulting from SCR installations are estimated to range from $0.09 million to $1.0 million per year. Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

The estimated TIC of SCR upgrades range from $22.2 million to $40.5 million. It is assumed that

20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs resulting from SCR upgrades are estimated to range from $0.12 million to $0.26 million per year. Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

The TIC of ULNB installations is estimated to range from $12.7 million to $27.4 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. The recurring O&M cost for each unit is estimated to be $0.1 million annually. The annual O&M costs are distributed among electricity (50%) and other annual maintenance (50%).

The TIC of SCR + ULNB installations is estimated to range from $8.3 million to $44.3 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to range from $0.09 million to $0.24 million per year. Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

The TIC of the SCR upgrade + ULNB installations is estimated at $22.2 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to be $0.21 million per year. Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

In addition, 64 heaters with a size less than 40 MMbtu have been identified as potential candidates for further emission reductions beyond the year 2033 with the expected future introduction of new emission control technology. These small heaters emitted 0.50 tpd of NOx based on 2017 emissions data.

The TIC of the emerging technology for small heaters is estimated to range from $0.59 million to $22.4 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to range from $0.069 million to $0.109 million per year. Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

Assuming a 25-year life for equipment and installation, and a discount rate of 4%, the NPV is of all capital costs is estimated at $1.65 billion. The NPV of all annual operating and maintenance costs is estimated to be $231.5 million. Table 5 presents detailed costs by refinery.

Table 5: Process Heaters – Net Present Value of All Equipment, Installation, and Annual Operating Costs (Millions of 2018 Dollars)

Refinery	Equipment Cost	Installation Cost	Total O&M	Electricity/Water	Ammonia/Caustic	Catalyst	Other Maintenance
1	$77.74	$310.94	$43.79	$13.14	$17.52	$8.76	$4.38
4	$58.75	$235.01	$24.33	$7.30	$9.73	$4.87	$2.43
5	$49.46	$197.85	$62.39	$18.72	$24.95	$12.48	$6.24
6	$27.58	$110.33	$26.02	$7.81	$10.41	$5.20	$2.60
7	$54.73	$218.92	$38.57	$11.57	$15.43	$7.71	$3.86
8	$18.95	$75.82	$12.39	$3.72	$4.96	$2.48	$1.24
9	$34.54	$138.15	$17.90	$5.37	$7.16	$3.58	$1.79
10	$2.65	$10.61	$2.50	$0.75	$1.00	$0.50	$0.25
11	$2.97	$11.87	$1.78	$0.53	$0.71	$0.36	$0.18
16	$2.46	$9.83	$1.80	$0.54	$0.72	$0.36	$0.18
Total	**$329.83**	**$1,319.32**	**$231.47**	**$69.44**	**$92.59**	**$46.29**	**$23.15**

Boilers

Boilers are combustion sources used to generate the steam necessary for plant operations. There are currently 28 boilers in operation potentially affected by PR 1109.1. In 2017, these 28 boilers emitted 2.55 tpd of NOx.

It is assumed that controlling NOx emissions from boilers will be accomplished by installing nine new SCR + ULNB at five refineries, one ULNB + SCR upgrade at one refinery, and one SCR upgrade at one refinery.

The TIC for the nine SCR + ULNB installations is estimated to range from $9.0 million to $39.1 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to range from $0.10 million to $0.21 million per year. Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

The TIC for the ULNB + SCR upgrade is estimated to be $14.0 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to be $0.20 million per year. Annual operating costs were assumed to be distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

The TIC for the SCR upgrade is estimated to be $18.1 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to be $0.24 million per year. Annual operating costs were assumed to be distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

In addition, an additional 5 boilers with a size less than 40 MMbtu have been identified as potential candidates for further emission reductions with the expected introduction of new emission control technology. The rule states that achieving 5 ppm is not required until the operator cumulatively replaces 50% or more of the burners starting from the date of rule adoption. These small boilers emitted 0.50 tpd of NOx based on 2017 emissions data.

The TIC for the emerging control technology for small boilers is estimated to be $6.38 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to be $0.068 million per year. Annual operating costs were assumed to be distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

Assuming a 25-year life for equipment and installation, and a discount rate of 4%, the NPV is of all capital costs is estimated at $182.8 million. The NPV of all annual operating and maintenance costs is estimated to be $28.72 million. Table 6 presents detailed costs by refinery.

Table 6: Boilers – Net Present Value of All Equipment, Installation, and Annual Operating Costs (Millions of 2018 Dollars)

Refinery	Equipment Cost	Installation Cost	Total O&M	Electricity/Water	Ammonia/Caustic	Catalyst	Other Maintenance
3	$2.68	$10.73	$1.60	$0.48	$0.64	$0.32	$0.16
4	$12.38	$49.52	$5.19	$1.56	$2.08	$1.04	$0.52
5	$2.44	$9.76	$2.55	$0.77	$1.02	$0.51	$0.26
6	$4.54	$18.15	$6.22	$1.87	$2.49	$1.24	$0.62
7	$8.03	$32.13	$7.17	$2.15	$2.87	$1.43	$0.72
8	$2.69	$10.77	$3.06	$0.92	$1.23	$0.61	$0.31
10	$1.64	$6.54	$1.25	$0.37	$0.50	$0.25	$0.12
16	$2.16	$8.65	$1.68	$0.50	$0.67	$0.34	$0.17
Total	**$36.56**	**$146.25**	**$28.72**	**$8.62**	**$11.49**	**$5.74**	**$2.87**

Steam Methane Reduction (SMR) Heaters

Steam methane reformers are specialized process heaters used in hydrogen production. Hydrogen is primarily used in the refining industry to reduce or remove contaminants such as nitrogen, metals, sulfur, olefins and aromatic content in fuels. There are currently 11 SMR heaters potentially affected by PR 1109.1. These 11 units emitted NOx at a rate of 1.02 tpd in 2017.

It is assumed that controlling NOx emissions from SMR heaters will be accomplished through the installation of SCR and SCR upgrades. In total, two new SCR installations are expected at two refineries and two SCR upgrades are expected at two refineries.

The TIC for the new SCR installations is estimated to range from $17.0 million to $32.0 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to be $0.20 million per year. Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

The TIC for the SCR upgrades is expected to range from $8.4 million to $11.4 million. It is assumed that 20% of one-time capital costs are attributed to equipment costs and the remaining 80% to installation. Annual O&M costs are estimated to range from $0.03 million to $0.06 million per year. Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

Assuming a 25-year life for equipment and installation, and a discount rate of 4%, the NPV is of all capital costs is estimated at $63.18 million. The NPV of all annual operating and maintenance costs is estimated to be $7.13 million. Table 7 presents detailed costs by refinery.

Table 7: SMR Heaters – Net Present Value of All Equipment, Installation, and Annual Operating Costs (Millions of 2018 Dollars)

Refinery	Equipment Cost	Installation Cost	Total O&M	Electricity/Water	Ammonia/Caustic	Catalyst	Other Maintenance
1	$2.032	$8.127	$0.783	$0.235	$0.313	$0.157	$0.078
6	$6.154	$24.615	$3.004	$0.901	$1.202	$0.601	$0.300
7	$1.180	$4.721	$0.274	$0.082	$0.110	$0.055	$0.027
8	$3.269	$13.077	$3.064	$0.919	$1.226	$0.613	$0.306
Total	**$12.635**	**$50.541**	**$7.126**	**$2.138**	**$2.851**	**$1.425**	**$0.713**

Gas Turbines

Gas turbines are used in refineries to produce both electricity and steam. There are a total of twelve gas turbines currently in operation at the refineries in the South Coast Air Basin. Currently, there are two gas turbines operating with natural gas achieving 2 ppmv NOx limit in practice. The total NOx emissions from the twelve gas turbines account for 1.45 tpd of NOx emissions.

All gas turbines operating with refinery gas have existing SCRs. For the purpose of the analysis, a total of five gas turbines across two refineries are assumed to complete SCR upgrades.

The estimated TIC of SCR upgrades ranges from $8.6 million to $12.3 million. It is assumed that 20% of the TIC is attributable to equipment costs with the remaining 80% resulting from installation. The estimated annual O&M cost ranges from $0.03 million to $0.15 million. It is assumed that 30% of the annual O&M costs is attributable to utility costs, 40% to ammonia, 20% to catalyst, and 10% to other periodic maintenance.

Assuming a 25-year life for equipment and installation, and a discount rate of 4%, the NPV is of all capital costs is estimated at $49.1 million. The NPV of all annual operating and maintenance costs is estimated to be $5.33 million. Table 8 presents detailed costs by refinery.

Table 8: Gas Turbines – Net Present Value of All Equipment, Installation, and Annual Operating Costs (Millions of 2018 Dollars)

Refinery	Equipment Cost	Installation Cost	Total O&M	Electricity/Water	Ammonia/Caustic	Catalyst	Other Maintenance
4	$2.837	$11.347	$3.932	$1.180	$1.573	$0.786	$0.393
5	$6.990	$27.960	$1.397	$0.419	$0.559	$0.279	$0.140
Total	**$9.827**	**$39.307**	**$5.329**	**$1.599**	**$2.132**	**$1.066**	**$0.533**

Sulfur Recovery Units and Tail Gas Units (SRU/TGUs)

Refinery SRU/TGUs, including their incinerators, are classified as major sources of both NOx and SOx emissions. Because sulfur is a naturally occurring and undesirable component of crude oil, refineries employ a sulfur recovery system to maximize sulfur removal.

There are 19 SRU/TGs currently operating in the South Coast AQMD emitting a cumulative total of 0.42 tpd of NOx. It is estimated that a total of nine Low-NOx burners will be installed across six facilities as a result of 1109.1 implementation.

The TIC of the nine ULNBs is estimated to range from $2.6 million to $6.1 million. It is assumed that 20% of the capital cost is attributable equipment acquisition cost with the remaining 80% resulting from installation. The recurring O&M cost for each unit is estimated to range from $2,000 to $4,000 annually. The annual O&M costs are distributed among electricity (50%) and other annual maintenance (50%).

Assuming a 25-year life for equipment and installation, and a discount rate of 4%, the NPV is of all capital costs is estimated at $26.6 million. The NPV of all annual operating and maintenance costs is estimated to be $0.281 million. Table 9 presents detailed costs by refinery.

Table 9: SRU/TG – Net Present Value of All Equipment, Installation, and Annual Operating Costs (Millions of 2018 Dollars)

Refinery	Equipment Cost	Installation Cost	Total O&M	Electricity/Water	Other Maintenance
1	$0.40	$1.58	$0.02	$0.01	$0.01
3	$0.80	$3.19	$0.04	$0.02	$0.02
5	$2.80	$11.19	$0.15	$0.07	$0.07
6	$0.43	$1.70	$0.02	$0.01	$0.01
9	$0.55	$2.20	$0.03	$0.01	$0.01
10	$0.36	$1.46	$0.02	$0.01	$0.01
Total	**$5.33**	**$21.32**	**$0.28**	**$0.14**	**$0.14**

Coke Calciner

Petroleum coke is the heaviest portion of crude oil which cannot be recovered in the normal oil refining process. Instead, it is processed in a delayed coker unit to generate a carbonaceous solid referred to as “green coke,” a commodity. To improve the quality of the product, it is sent to a calciner to make calcined petroleum coke.

There is currently only one coke calciner in operation in the South Coast Air Basin. This unit currently emits NOx at a rate of 0.71 tpd.

This analysis assumes that the coke calciner will be retrofitted with SCR. Cost estimates for SCR systems provided by vendors range from $5 million to $8 million per unit. One-time installation costs are estimated to be 4.5 times of the equipment cost based on the recommendation by NEC in the 2015 BARCT assessment. The TIC is assumed to be $44.0 million with an assumed equipment cost of $8 million and installation costs of $36 million.

Staff estimated the annual O&M cost to be $458,000, based on the annual operating costs reported in the survey for a SCR installed on a gas turbine.[14] Annual operating costs were distributed among electricity (30%), ammonia (40%), catalyst (20%), and other annual maintenance (10%).

Assuming a 25-year life for equipment and installation, and a discount rate of 4%, the NPV is of all capital costs is estimated at $39.1 million. The NPV of all annual operating and maintenance costs is estimated to be $6.36 million.

Vapor Incinerators

Vapor Incinerators are one of the most proven methods to control VOCs emissions released form industrial sources by means of thermal destruction. The term "incineration" refers to an ultimate disposal method which is a thermal treatment of waste materials (solid, liquid, or gas) through a combustion process in the presence of oxygen.

There is currently a total of 13 vapor incinerators, afterburners, and thermal oxidizers in operation in the South Coast Air Basin. The total NOx emissions from the 13 vapor incinerators located in the South Coast AQMD is 0.08 tpd.

This analysis assumes that eight vapor incinerators across four facilities will be retrofitted with ULNBs. The TIC for the eight ULNBs is estimated to range from $0.3 million to $4.9 million per unit. One-time capital costs are distributed between equipment (20%) and installation (80%) costs. Recurring O&M costs are estimated to be $2,000 annually per unit. O&M costs are distributed between electricity (50%)and other periodic maintenance (50%).

Assuming a 25-year life for equipment and installation, and a discount rate of 4%, the NPV is of all capital costs is estimated at $8.97 million. The NPV of all annual operating and maintenance costs is estimated to be $0.197 million. Table 10 presents the detailed costs by refinery.

[14] Gas turbines were chosen as a reference point because the flue gas flow rate is similar to that of the calciner. Staff also included the additional cost required to fuel the duct burner that will heat the flue gas to the appropriate temperature for the low-temperature catalysts.

Table 10: Vapor Incinerators – Net Present Value of All Equipment, Installation, and Annual Operating Costs (Millions of 2018 Dollars)

Refinery	Equipment Cost	Installation Cost	Total O&M	Electricity/Water	Other Maintenance
5	$0.29	$1.16	$0.06	$0.03	$0.03
6	$0.17	$0.67	$0.02	$0.01	$0.01
10	$0.86	$3.44	$0.07	$0.04	$0.04
11	$0.48	$1.90	$0.04	$0.02	$0.02
Total	**$1.80**	**$7.18**	**$0.20**	**$0.10**	**$0.10**

Tables 11 below summarizes the estimated total equipment costs expected to result from PR 1109.1. Table 11 includes the total discounted cost (NPV) and average annual cost capital, O&M, and total costs by equipment category assuming a 4% real interest rate. It is expected that discounted total costs will be $2.36 billion and average annual total costs will be $133.88 million.

Table 11: Summary of Costs by Equipment Category (in Millions of 2018 Dollars)

Equipment Category	NPV			Average Annual		
	Capital	O&M	Total	Capital	O&M	Total
Boiler	$182.81	$28.72	$211.54	$9.81	$1.51	$11.32
Coke Calciner	$39.12	$6.36	$45.48	$1.96	$0.32	$2.27
FCCU	$61.52	$3.62	$65.15	$3.47	$0.19	$3.66
Gas Turbine	$49.13	$5.33	$54.46	$2.38	$0.28	$2.66
Heater	$1,649.15	$231.47	$1,880.62	$95.40	$13.05	$108.45
SMR Heater	$63.18	$7.13	$70.30	$3.06	$0.34	$3.40
SRU/TG	$26.65	$0.28	$26.93	$1.58	$0.02	$1.60
Vapor Incinerator	$8.97	$0.20	$9.17	$0.52	$0.01	$0.53
Total	**$2,080.54**	**$283.11**	**$2,363.64**	**$118.18**	**$15.70**	**$133.88**

Administrative Costs

Permitting and Plan Fees

Facilities installing new pollution control equipment will also incur additional administrative costs, such as compliance plan submission and permitting fees. Twelve facilities are expected to submit compliance plans. Plan submission fees are one-time costs billed at an hourly rate of $211.24 per hour and it is assumed that review of each compliance plan will require 120 hours of staff time.

Affected facilities are also expected to incur one-time permitting costs due to permit processing for SCR applications ($6,104.08 per unit), change of condition to heater/boiler equipment permits ($8,308.45 per unit), processing fee for new burner heater/boiler equipment permits ($9,685.81 per unit), and Title V permit revisions ($2,853.99 per unit). Additionally, facilities installing new SCRs will incur annual permitting costs of $1,975.52 per unit per year. Table 12 below includes a breakdown of plan submission and permitting costs, including the number of expected projects, the year cost is incurred, and NPV (in millions of dollars).

Table 12: Plan Submission and Permitting Fees (Millions of Dollars)

Action	2022		2023		2025		2028		Total
	# of Projects	NPV	# of Projects	NPV	# of Projects	NPV	# of Projects	NPV	
Plan Submittal Fee	12	$0.29	-	-	-	-	-	-	$0.29
Permit Processing Fee for SCR Applications	-	-	45	$0.25	27	$0.14	17	$0.08	$0.47
Change of Condition to Heater/Boiler Equipment Permits	-	-	45	$0.35	27	$0.19	17	$0.11	$0.64
Permit Processing Fee for New Burners Heater/Boiler Equipment Permits	-	-	38	$0.34	23	$0.19	15	$0.11	$0.64
Title V Permit Revision for All Potential Applications	-	-	83	$0.22	49	$0.12	33	$0.07	$0.41
Annual Permit Fees	-	-	-	-	-	-	-	-	$2.50
Total		**$0.29**		**$1.16**		**$0.64**		**$0.37**	**$4.67**

Potential Cost Savings Due to Reduced Emissions

Due to the large emission reductions projected from implementation of PR 1109.1, it is expected that affected facilities will incur a cost savings from reduced emission fees. Estimated cost savings were calculated using the estimated annual NOx emission reductions and assuming costs of $836.23 per ton of NOx for those facilities emitting more than 75 tons per year (Refineries 1-9) and $349.55 per ton of NOx for those facilities emitting more than 4 tons but less than 25 tons per expected to reach $2.38 million per year upon full implementation.[15] See Table 13 and 14 below for a breakdown of projected NOx emissions and estimated cost savings by refinery.

[15] South Coast AQMD fees may be raised in future years to account for the decrease in revenue, however It is uncertain whether emission fees will be raised or some other fees.

Table 13: Projected NOx Emission Reductions by Refinery by Year (tpd)

Refinery	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033 – 2047*
1	0.06	0.06	0.13	0.31	0.32	0.44	0.44	0.61	0.63	0.64	0.65
2	0.00	0.00	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09	0.10
4	0.00	0.15	0.17	0.51	0.86	1.03	1.42	1.49	1.49	1.52	1.54
5	0.24	0.45	0.45	0.62	0.76	0.92	0.99	0.99	0.99	1.02	1.08
6	1.53	1.53	1.53	1.58	1.70	1.71	1.71	1.71	1.71	1.72	1.72
7	0.39	0.39	0.46	0.56	0.65	0.65	0.65	0.65	0.80	0.80	0.80
8	0.46	0.64	0.68	0.73	0.73	0.73	0.83	0.83	0.83	0.83	0.83
9	0.00	0.07	0.09	0.09	0.11	0.11	0.15	0.37	0.39	0.40	0.42
10	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.02	0.03	0.03	0.03
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Total	**2.68**	**3.29**	**4.18**	**5.07**	**5.79**	**6.29**	**6.87**	**7.33**	**7.62**	**7.72**	**7.83**

*Emission reductions occur at the level reported in each year of the time horizon (2033, 2034,…, 2047)

Table 14: Projected Cost Savings Due to Reduced NOx Emissions by Refinery by Year (Millions of 2018 dollars)

Refinery	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033 - 2047*
1	$0.019	$0.019	$0.041	$0.096	$0.098	$0.135	$0.135	$0.186	$0.193	$0.196	$0.199
2	$0.000	$0.000	$0.201	$0.201	$0.201	$0.201	$0.201	$0.201	$0.201	$0.201	$0.201
3	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.026	$0.026	$0.030
4	$0.000	$0.045	$0.053	$0.155	$0.263	$0.316	$0.434	$0.456	$0.456	$0.465	$0.470
5	$0.073	$0.138	$0.138	$0.189	$0.231	$0.281	$0.301	$0.301	$0.301	$0.312	$0.330
6	$0.466	$0.466	$0.466	$0.482	$0.518	$0.523	$0.523	$0.523	$0.523	$0.525	$0.525
7	$0.119	$0.119	$0.140	$0.171	$0.200	$0.200	$0.200	$0.200	$0.245	$0.245	$0.245
8	$0.141	$0.195	$0.207	$0.224	$0.224	$0.224	$0.252	$0.252	$0.252	$0.252	$0.252
9	$0.000	$0.023	$0.029	$0.029	$0.033	$0.033	$0.045	$0.112	$0.118	$0.123	$0.128
10	$0.000	$0.000	$0.000	$0.000	$0.000	$0.003	$0.003	$0.003	$0.004	$0.004	$0.004
11	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.001	$0.001	$0.001
Total	**$0.818**	**$1.005**	**$1.275**	**$1.547**	**$1.768**	**$1.916**	**$2.094**	**$2.233**	**$2.320**	**$2.351**	**$2.385**

*Cost savings are incurred at the level reported in each year of the time horizon (2033, 2034,…, 2047)

Total Compliance Costs

Total compliance costs in Table 15 below include costs form equipment acquisition and installation, annual O&M costs associated with equipment use, administrative costs, such as permitting and plan fees, and potential cost savings from reduced emissions fees paid. Table 15 includes the total discounted cost (NPV) and average annual cost by cost category for both a 1% and 4% real interest rate.[16] Total discounted costs are expected to range from $2.336 billion to $2.920 billion based on 4% and 1% discount rates, respectively, and the average annual total costs of PR 1109.1 is expected to range from $98.10 million to $132.45 million per year.

Table 15: Total Compliance Costs (in Millions of 2018 Dollars)

Cost Category	**NPV**		**Average Annual (2022 - 2057)**	
	1%	**4%**	**1%**	**4%**
Capital Costs	$2,494.02	$2,080.54	$83.83	$118.18
O&M Costs	$469.96	$283.11	$15.70	$15.70
Administrative Costs	$6.69	$4.96	$0.22	$0.22
Emissions Fees	-$50.63	-$32.36	-$1.66	-$1.66
Total	**$2,920.03**	**$2,336.24**	**$98.10**	**$132.45**

MACROECONOMIC IMPACTS ON THE REGIONAL ECONOMY

The Regional Economic Model (REMI, PI+ v2.5.0) was used to assess the total socioeconomic impacts of the anticipated policy change (i.e., the proposed rule).[17][18] The model links the economic activities in the counties of Los Angeles, Orange, Riverside, and San Bernardino, and for each county, it is comprised of five interrelated blocks: (1) output and demand, (2) labor and capital, (3) population and labor force, (4) wages, prices and costs, and (5) market shares.[19]

It should be noted that the REMI model is not designed to assess impacts on individual operations. The model was used to assess the impacts of the proposed project on various industries that make

[16] Annualizing costs using the high real interest rate (4%) results in higher annual costs when compared to annualized costs using the low real interest rate (1%). This is due to the fact that higher financing costs are incurred at higher interest rates holding all else constant.

[17] Regional Economic Modeling Inc. (REMI). Policy Insight® for the South Coast Area (160-sector model). Version 2.5.0, 2021.

[18] REMI v2.5.0 has been updated based on The U.S. Economic Outlook for 2021-2023 from the University of Michigan's Research Seminar in Quantitative Economics (RSQE) release on May 21, 2021, The Long-Term Economic Projections from CBO (supplementing CBO's March 2021 report The 2021 Long-Term Budget Outlook), and updated BEA data for 2020 (revised on May 27, 2021).

[19] Within each county, producers are made up of 156 private non-farm industries and sectors, three government sectors, and a farm sector. Trade flows are captured between sectors as well as across the four counties and the rest of U.S. Market shares of industries are dependent upon their product prices, access to production inputs, and local infrastructure. The demographic/migration component has 160 ages/gender/race/ethnicity cohorts and captures population changes in births, deaths, and migration. (For details, please refer to REMI online documentation at http://www.remi.com/products/pi.)

up the local economy. Cost impacts on individual operations were assessed outside of the REMI model and used as inputs into the REMI model.

Impact of Proposed Amendments

The assessment herein is performed relative to a baseline ("business as usual") where the proposed amendments would not be implemented. It is assumed that the 16 facilities would finance the capital and installation costs of control equipment, or more specifically, these one-time costs are assumed to be amortized and incurred over the equipment life. The proposed project is assumed to induce full BARCT installation at the 16 affected facilities, which would create a policy scenario under which the affected facilities would incur an average annual compliance cost of approximately $133.88 million when costs are annualized using a 4% real interest rate, or $99.53 million when evaluated using a 1% real interest rate from year 2022 onwards when all controls are assumed to have been installed.

Direct effects of the proposed project are used as inputs to the REMI model in order for the model to assess secondary and induced impacts for all the industries in the four-county economy on an annual basis and across a user-defined horizon: 2022 (first year when the affected facilities are assumed to incur compliance costs due to BARCT implementation) to 2057 (last year cost associated with equipment installation are incurred). Direct effects of the proposed amendments include (1) additional costs (net of cost savings due to lower emissions fees) to the 16 facilities that would install control equipment, (2) additional sales by local vendors of equipment, devices, or services that would meet the proposed requirements, and (3) increased fuel costs to all industries and consumers in the region.

Whereas all the compliance expenditures that are incurred by the affected facilities would increase their cost of doing business, the purchase of additional control equipment such as SCR, ULNB, and equipment installation would increase the spending and sales of businesses in various sectors, some of which may be located in the South Coast AQMD region. Table 16 lists the industry sectors modeled in REMI that would either incur cost or benefit from the compliance expenditures.

Table 16: Industries Incurring *vs.* Benefitting from Compliance Costs/Spending

Source of Compliance Costs	REMI Industries Incurring Compliance Costs	REMI Industries Benefitting from Compliance Spending
Installation of SCR and ULNB technology	Petroleum and Coal Products Manufacturing (NAICS 324), Basic Chemical Manufacturing (NAICS 3251)	*One-time-Capital:* Industrial Machinery Manufacturing (NAICS 3332)
Installation of SCR and ULNB technology	Petroleum and Coal Products Manufacturing (NAICS 324), Basic Chemical Manufacturing (NAICS 3251)	*One-time-Capital:* Construction (NAICS 23)
Permitting and Plan Submission Fees	Petroleum and Coal Products Manufacturing (NAICS 324), Basic Chemical Manufacturing (NAICS 3251)	*One-time-Capital:* State and Local Government (NAICS 92)
Operating and Maintenance Costs: Other Maintenance	Petroleum and Coal Products Manufacturing (NAICS 324), Basic Chemical Manufacturing (NAICS 3251)	*Recurring:* Other Professional, Scientific, and Technical Services (NAICS 5419)
Operating and Maintenance Costs: Electricity, Water	Petroleum and Coal Products Manufacturing (NAICS 324), Basic Chemical Manufacturing (NAICS 3251)	*Recurring:* Electric Power Generation, Transmission, and Distribution (NAICS 2211)
Operating and Maintenance Costs: Ammonia, Caustic	Petroleum and Coal Products Manufacturing (NAICS 324), Basic Chemical Manufacturing (NAICS 3251)	*Recurring:* Basic Chemical Manufacturing (NAICS 3251)
Operating and Maintenance Costs: Cost Savings Due to Reduced Emissions Fees	State and Local Government (NAICS 92)	*Recurring:* Petroleum and Coal Products Manufacturing (NAICS 324), Basic Chemical Manufacturing (NAICS 3251)

Source of Compliance Costs	REMI Industries Incurring Compliance Costs	REMI Industries Benefitting from Compliance Spending
Operating and Maintenance Costs: Annual Permit Fees	Petroleum and Coal Products Manufacturing (NAICS 324), Basic Chemical Manufacturing (NAICS 3251)	*Recurring:* State and Local Government (NAICS 92)

Impacts on Regional Fuel Prices

The impact analysis assumes that facilities will pass on a percentage of their compliance costs onto consumers and local industries through an increase in the regional price of gasoline. Based on the report included in Appendix A, "The Impact of Proposed Rule 1109.1 on Fuel Prices and Demand in South Coast AQMD Region," it is assumed that 30% of total annual O&M costs, including the cost savings due to reduced emission fees, is passed on to consumers and industries through increased gasoline prices.

REMI requires that modeled changes in fuel prices be inputted as a percentage change. To calculate the percentage increase in fuel price we first calculate the per gallon cost of compliance by dividing total annual passed through O&M costs (or 30% of total annual O&M costs) by total annual refinery distillation capacity.[20] The average annual increase in the price of gasoline is estimated to be .0035 cents per gallon. Then the calculated per gallon cost is divided by future projected gasoline price. The future gasoline price is based on the U.S. Energy Information Administration (EIA) motor gasoline price projections for 2021-2050.[21,22] Based on recent historical annual gasoline price data (2015-2020) from EIA (see Figure 1) it is assumed that future average gasoline prices in California are 29% higher than the projected average US price.[23] See Figure 2 below for the annual projected gasoline price for the U.S. and California from 2021-2050.

[20] Estimates of 2019 annual distillation capacity by refinery (in bbl/day) can be found in Table 1 of Appendix A. It is assumed that 42 gallons of petroleum products are produced per bbl. In addition, an average refinery capacity factor of 0.873 is assumed based on the 20-year average for PADD 5 reported by the EIA.
[21] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=12-AEO2021&cases=ref2021~aeo2020ref&sourcekey=0
[22] EIA gasoline price projections were provided in 2020 dollars. The August 2021 update to the Marshall and Swift Cost Index was used to convert future prices to 2018 dollars.
[23] 2015-2020 historical annual average 'all grade' price data for the US and California can be found here: https://www.eia.gov/dnav/pet/pet_pri_gnd_dcus_nus_w.htm

Figure 1: Historical Annual Average Per Gallon Gasoline Price for U.S. and California

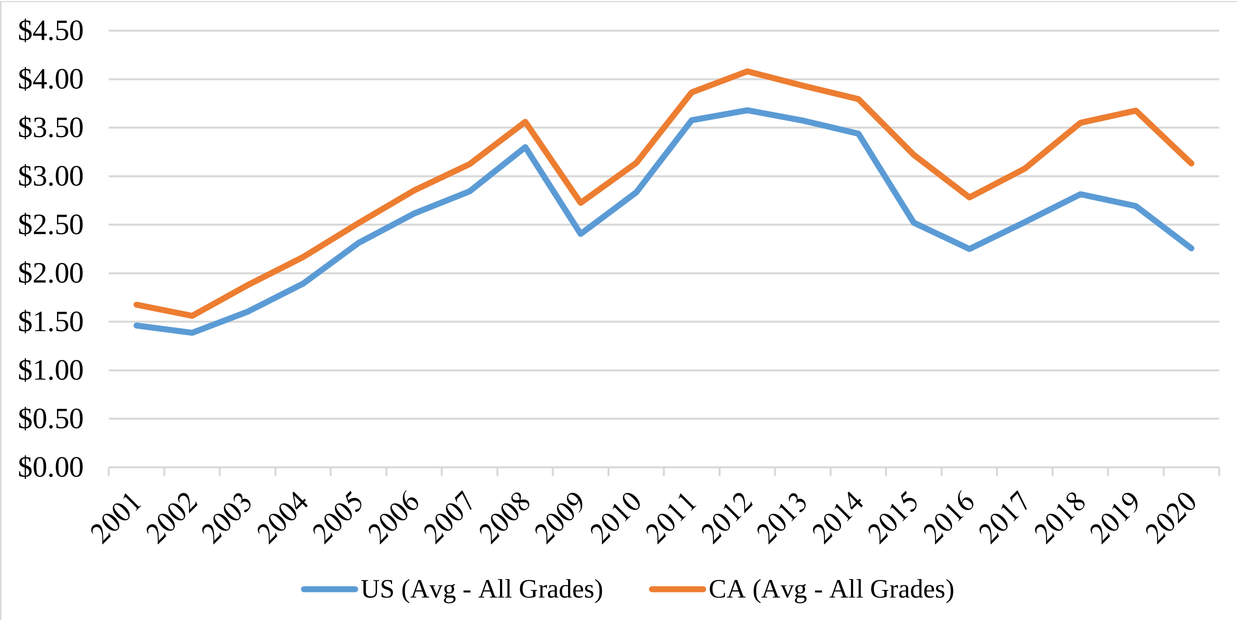
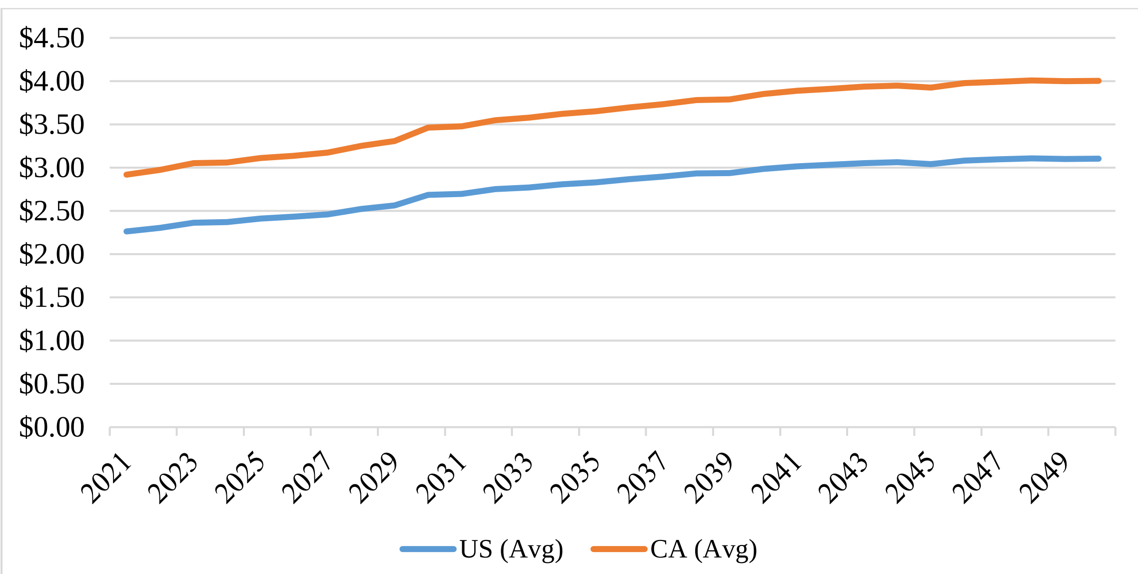
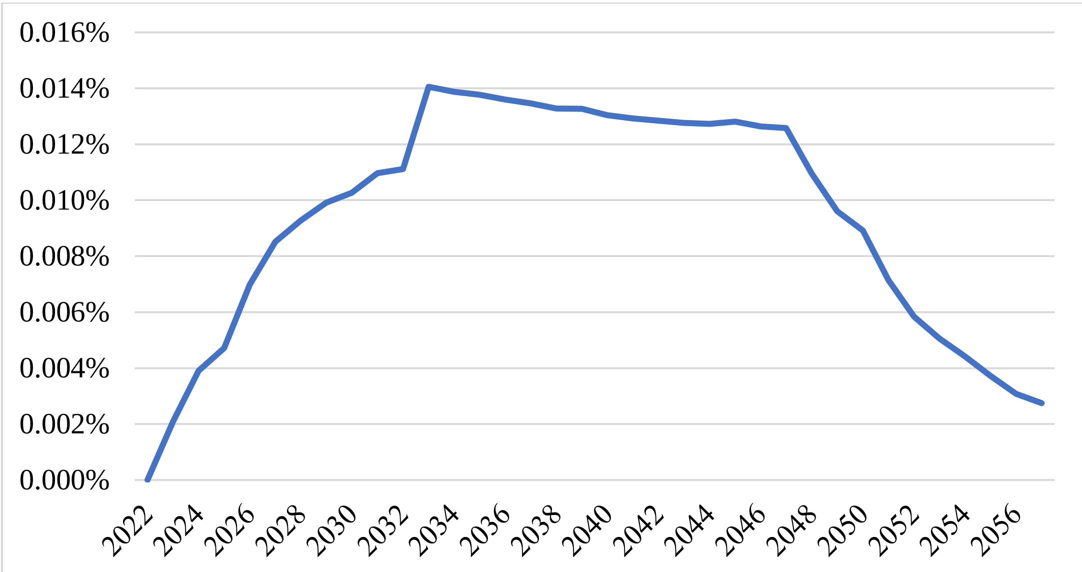


Figure 2: U.S. and California Projected Per Gallon Gasoline Price 2021-2050 (in 2018 dollars)



The estimated annual percentage increase in gasoline price is shown below in Figure 3. Gas prices are expected to slowly increase as control equipment is installed over time. A maximum percentage increase of 0.014% is reached in 2033 upon full implementation of the rule. After 2033, price increases are expected to steadily decline as O&M costs remain constant and gas price projections steadily rise. In later years, impacts to fuel prices decline dramatically due to expected lower annual O&M costs.

Figure 3: Estimated Percentage Increase in Gasoline Prices Resulting from PR 1109.1 Implementation



Regional Job Impacts

When the compliance cost is annualized using a 4% real interest rate, it is projected that an annual average of 213 net jobs could be created annually from 2022 to 2057. The projected job impact is more positive (342 jobs created annually) when the compliance cost annualized at a 1% interest rate is used.

In earlier years of the implementation, the positive job impacts from the compliance expenditures made by affected facilities would more than offset the jobs forgone from the additional cost of doing business (Table 17). From 2022-2032, it is projected that an average of 1,837 jobs would be added annually. In 2032, when most of the spending is expected to occur, about 4,435 additional jobs are projected in the regional economy. The positive job impact would trickle down to the sectors of construction, miscellaneous professional services, retail & wholesale trade, food services, and real estate. However, as affected facilities continue to incur the amortized capital expenditures and annual O&M costs, reductions in job growth would set in, resulting in jobs forgone in later years.

Despite incurring the majority of the total compliance cost, the petroleum and coal products manufacturing industry (NAICS 324) is projected to experience only minor impacts in terms of jobs forgone (14 on average). This is due to the fact that the industry is capital-intensive. As such, less labor would be required to produce the same amount of products or services.

In earlier years, positive job impacts are projected in the sectors of architectural and structural metals manufacturing (NAICS 3323) and industrial machinery manufacturing (NAICS 3332), due to purchase of various types of control equipment (including SCR and ULNB) by the affected facilities (as presented in Table 17). Likewise, the construction sector is projected to gain many jobs during the early years of the time horizon, due to the installation of control equipment. In addition, the sector of other professional, scientific, and technical services (NAICS 5419) is projected to also gain jobs across the entire planning horizon. Operating and maintenance expenditures would benefit the industries of basic chemical manufacturing (NAICS 3251) for additional sales of ammonia and electricity generation, transmission, and distribution (NAICS 2211) for electricity.

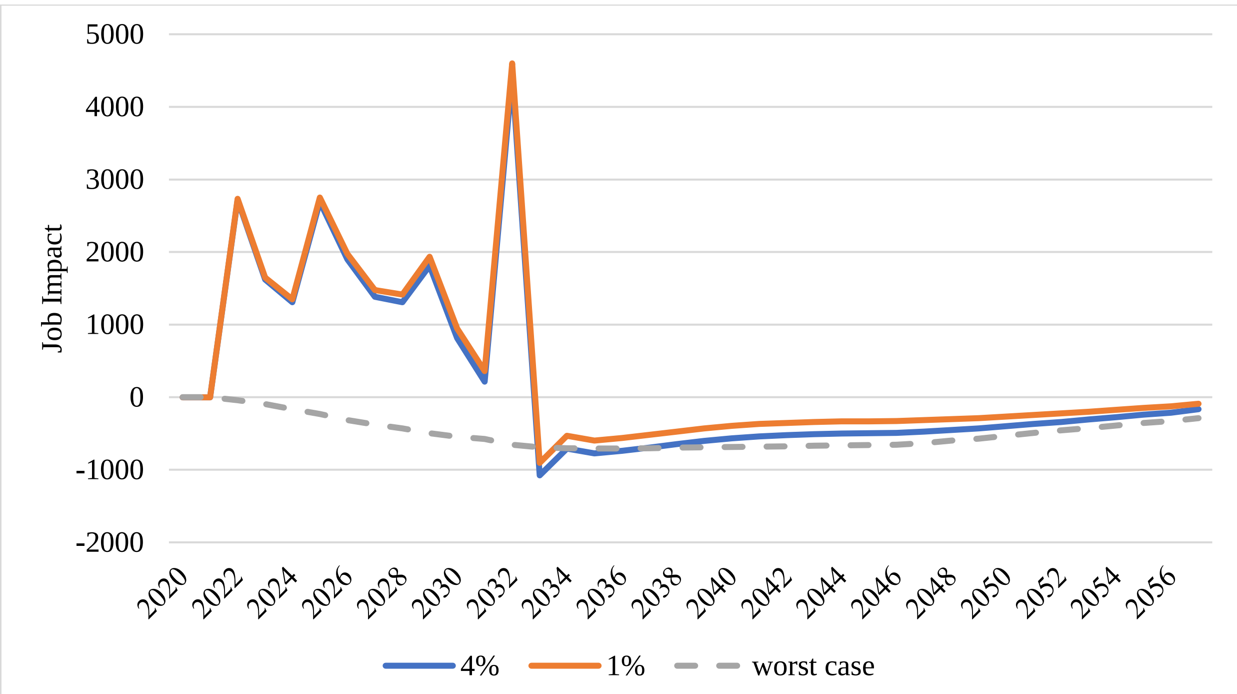
The projected reduction in disposable income from the overall jobs forgone in the later years would dampen the demand for goods and services in the local economy, thus contributing to jobs forgone in sectors such as the rest of manufacturing, retail trade, wholesale, and accommodation and food services. As presented in Table 17, many major sectors of the regional economy would experience negative, albeit minor, job impacts in later years from the secondary and induced effects of BARCT implementation.

Table 17: Projected Job Impacts of Full BARCT Implementation for Select Industries by Year

Industry	2022	2027	2032	2037	2047	2057	Average Annual (2022-2057)	Baseline Average Annual (2022-2057)	% Change from Baseline
Construction (23)	1,429	897	2,669	-189	-55	5	283	572,266	0.049%
Other professional, scientific, and technical services (5419)	9	11	26	10	10	1	9	76,008	0.012%
Offices of health practitioners (6211-6213)	62	21	104	-6	-2	0	7	392,074	0.002%
Industrial machinery manufacturing (3332)	27	17	40	0	0	0	6	1,238	0.501%
Architectural and structural metals manufacturing (3323)	23	14	40	-3	-1	0	5	18,759	0.024%
Architectural, engineering, and related services (5413)	36	17	53	-10	-5	-1	3	105,440	0.003%
Retail trade (44-45)	173	56	203	-46	-34	-8	1	926,446	0.000%
Basic chemical manufacturing (3251)	0	1	1	0	0	0	0	2,204	0.006%
Waste management and remediation services (562)	4	1	5	-3	-2	-1	-1	26,845	-0.004%
Food services and drinking places (722)	73	42	123	-22	-33	-17	-2	729,552	0.000%
Real estate (531)	70	18	95	-18	-17	-12	-2	615,022	0.000%
Oil and gas extraction (211)	0	-2	-5	-6	-5	-1	-4	1,863	-0.206%
Management, scientific, and technical consulting services (5416)	17	4	20	-13	-10	-4	-5	195,135	-0.003%
Warehousing and storage (493)	11	-2	4	-12	-7	-1	-6	101,407	-0.005%
Wholesale trade (42)	62	15	67	-33	-23	-7	-9	421,576	-0.002%
Transit and ground passenger transportation (485)	22	6	33	-26	-25	-12	-13	349,167	-0.004%
Petroleum and coal products manufacturing (324)	0	-7	-15	-21	-18	-6	-14	4,527	-0.307%
State and Local Government (92)	85	95	136	-86	-94	-36	-23	1,016,786	-0.002%
All Industries	**2,720**	**1,384**	**4,435**	**-695**	**-473**	**-166**	**213**	**11,889,543**	**0.002%**

Figure 4 presents a projected time series of job impacts over the 2020-2057 time horizon. Based on Abt Associate's 2014 recommendation to enhance socioeconomic analysis by conducting scenario analysis on major assumptions, staff has analyzed an alternative scenario (worst case) where the affected facilities would not purchase any control equipment or services from providers within the Basin. This is a hypothetical scenario in order to test the sensitivity of the previously discussed scenarios where the analyses rely on REMI's embedded assumptions about how the capital and O&M spending would be distributed inside and outside the region. In reality, utilities expenditures are paid to local utilities producers. Moreover, construction jobs related to control installation are likely to increase hiring from the local labor force. This worst-case scenario would result in an annual average of approximately 516 jobs forgone. The 516 jobs forgone represents less than 0.005% of total jobs in the region.

Figure 4: Projected Regional Job Impact, 2020-2057



Competitiveness

For an analysis of the expected impacts of PR 1109.1 on regional fuel prices, please see the Impacts of Regional Fuel Prices section of this document. Estimated impacts are based on the assumption that 30% of annual O&M costs are passed on to consumers. For added context, if 100% of all costs (capital and O&M) were passed on to consumers, it is projected that gasoline prices will increase by 0.99 cents per gallon (or a 0.26% increase) on average, with a maximum expected increase of 1.42 cents per gallon (or a 0.40% increase).

Job Impacts by Occupation and Income Group

REMI provides a breakdown job impacts by occupation type. See Table 18 below for the projected job impacts by year for each major occupation category. All job impacts across the region are accounted for in Table 18. Construction and extraction occupations are projected to experience the largest growth in employment as a result of PR 1109.1. This occupation category includes trade workers, helpers, extraction workers and supervisors. Installation, maintenance and repair occupations are also expected to experience relatively strong employment growth. This category includes electrical and electronic equipment mechanics, installers & repairers, as well as vehicle and mobile equipment mechanics, installers & repairers. Legal workers, educators, protective workers (fire, police), and life & physical scientists are all projected to experience minor negative job impacts.

Table 18: Job Impacts by Occupation, 2022-2057

Occupation	2022	2027	2032	2037	2047	2057	Annual Average (2022-2057)	Baseline Annual Average (2022-2057)	% Change from Baseline
Management, business, and financial operations occupations	295	143	480	-84	-56	-21	17	1,521,282	0.001%
Computer, mathematical, architecture, and engineering occupations	84	35	120	-35	-26	-11	-3	585,436	-0.001%
Life, physical, and social science occupations	10	5	15	-6	-5	-2	-1	86,290	-0.001%
Community and social service occupations	14	9	23	-6	-7	-3	-1	192,777	0.000%
Legal occupations	14	5	18	-8	-5	-2	-1	120,057	-0.001%
Educational instruction and library occupations	46	41	73	-34	-38	-17	-8	553,075	-0.001%
Arts, design, entertainment, sports, and media occupations	20	4	27	-6	-3	-3	0	374,024	0.000%
Healthcare occupations	128	57	218	-20	-21	-11	10	1,304,086	0.001%
Protective service occupations	25	14	35	-18	-16	-6	-5	260,916	-0.002%
Food preparation and serving related occupations	84	46	139	-26	-35	-18	-2	847,583	0.000%

Building and grounds cleaning and maintenance, personal care and service occupations	108	38	167	-29	-24	-9	1	863,635	0.000%
Sales and related, office and administrative support occupations	489	200	685	-130	-86	-28	21	2,511,233	0.001%
Farming, fishing, and forestry occupations	1	1	2	-1	0	0	0	24,040	0.000%
Construction and extraction occupations	896	562	1,678	-127	-42	1	173	447,963	0.039%
Installation, maintenance, and repair occupations	199	107	340	-46	-28	-9	21	538,948	0.004%
Production occupations	120	47	158	-35	-20	-6	4	445,549	0.001%
Transportation and material moving occupations	186	69	258	-86	-62	-20	-13	1,167,112	-0.001%
Military	0	0	0	0	0	0	0	45539	0.000%
All Occupations	**2720**	**1384**	**4435**	**-695**	**-473**	**-166**	**213**	**11889543**	**0.002%**

REMI also groups occupations into five categories according to income quintiles. Group 1 has the lowest-paid occupations while Group 5 has the highest-paid occupations. Table 19 below shows the job impact as a percentage of the baseline jobs under the proposed amendments for each occupational wage group.

A positive figure indicates that the proposed amendments create more jobs and a negative figure means the opposite. In earlier years of the implementation of these amendments, the positive job impacts from the compliance expenditures made by affected facilities would more than offset the jobs proportionally forgone from the additional cost of doing business. However, as affected facilities continue to incur the amortized capital expenditures, reductions in job growth would set in, resulting in jobs forgone in later years.

As shown in Table 18, from 2022 through 2032, the full installation of BARCT controls is projected to result in more jobs created with respect to the baseline for all occupational groups. In later years, however, proportionately fewer jobs would be foregone for lower paid than higher paid jobs.

Table 19: Job Impact of the Proposed Amendments by Occupational Wage Group by Year

Occupational Income Group	% Impact from Baseline					
	2022	2027	2032	2037	2047	2057
Group 1 (1st 20%)	0.013%	0.005%	0.018%	-0.003%	-0.003%	-0.001%
Group 2 (2nd 20%)	0.020%	0.008%	0.029%	-0.006%	-0.004%	-0.001%
Group 3 (3rd 20%)	0.049%	0.027%	0.084%	-0.009%	-0.005%	-0.001%
Group 4 (4th 20%)	0.023%	0.012%	0.037%	-0.007%	-0.005%	-0.002%
Group 5 (5th 20%)	0.017%	0.008%	0.026%	-0.005%	-0.004%	-0.001%

Comparison of Cost-Effectiveness with Recently Adopted RECLAIM Landing Rules

The proposed rule partially implements the emission control strategy CMB-05 – Further NOx Reductions from RECLAIM Assessment from the 2016 AQMP. Table 20 below includes the overall discounted cash flow (DCF) cost-effectiveness (across all equipment categories) for PR 1109.1 and other recently adopted RECLAIM landing rules as calculated in their respective Socioeconomic Impact Assessment. It shows that the overall cost-effectiveness for PR 1109.1 is within the cost-effectiveness range of other RECLAIM landing rules.

Table 20: Cost-Effectiveness of Recently Adopted RECLAIM Landing Rules

Rule	Date of Adoption	DCF Cost-effectiveness ($/ton)
1135	11/2/2018	$7,500
1146 Series	12/7/2018	$26,500
1118.1	1/4/2019	$45,000
1134	4/5/2019	$8,000
1110.2	11/7/2019	$32,000
1117	6/5/2020	$22,700
1109.1	-	$32,700

Incremental Cost-Effectiveness

Please refer to the most recent version of the Staff Report.

CEQA ALTERNATIVES

Four alternatives to the proposed amendments were developed for the CEQA analysis associated with this proposal, Alternative A - No Project, Alternative B - More Stringent, Alternative C - Less

Stringent, and Alternative D - Limited Start-Up, Shutdown, Malfunction. This section provides a description of each alternative as well as an assessment of the possible socioeconomic impacts resulting from these alternatives.

Alternative A – No Project

CEQA requires the specific alternative of "No Project" to be evaluated. A "No Project" Alternative consists of what would occur if the proposed project was not approved; in this case, not adopting the proposed rule. Alternative A is the "No Project" approach such that petroleum refineries and facilities related to petroleum refineries would remain under the NOx RECLAIM program and not be subject to a command-and-control rule. Since the transition of RECLAIM facilities into a command and control approach was the directive under control measure CMB-05 in the 2016 AQMP, the "No Project" alternative would hinder the full implementation of the control measure, not achieve the anticipated emission reductions in a timely manner, or satisfy the objectives of the proposed project.

However, remaining subject to the RECLAIM program under Alternative A would not eliminate the state law in Assembly Bill 617 that requires air districts "in nonattainment for one or more air pollutants to adopt an expedited schedule for the implementation of best available retrofit control technology, as specified." The bill applies to each industrial source that, as of January 1, 2017, was subject to a specified market-based compliance mechanism (e.g., RECLAIM or GHG Cap and Trade) and gives highest priority to those permitted units that have not modified emissions-related permit conditions for the greatest period of time. Thus, facilities would still need to be evaluated under a BARCT analysis and, depending on the outcome of that analysis, would need to take action to comply. However, the BARCT analysis under Alternative A and the proposed project is expected to be the same with the same determinations and NOx emission limits. The major difference is that under the RECLAIM program, facilities could potentially opt to use RECLAIM trading credits (RTCs) to meet allocation goals and not install physical control technology. Facilities under Alternative A could also be subject to a different implementation period to demonstrate compliance with the BARCT NOx emission limit. Other elements in the rule such as averaging times, exemptions, recordkeeping, reporting, and monitoring may also be different under the RECLAIM program.

The costs associated with complying with BARCT under RECLAIM are speculative, given the uncertainty surrounding the use of RTCs to meet compliance targets. As a result, for the purpose of this socioeconomic analysis, staff has assumed that costs for Alternative A would be identical to the costs associated with the proposed project given that the BARCT requirements would be the same under the 'No Project' scenario. This is a conservative approach because RECLAIM facilities would be expected to comply using RTCs if that is more cost-effective.

Alternative B - More Stringent Proposed Project

Under the proposed project, there is a set of requirements for some equipment categories, such as small boilers and heaters, that would not need to meet a lower NOx limit at this time due to the determination that is not cost effective under the BARCT analysis or the technology required to meet the lower limit is considered “emerging”. The proposed project, however, does require the equipment to meet the lower NOx limit at a future date. In the case of the small boilers less than 40 MMBTU/hour, achieving 5 ppm is not required until the operator cumulatively replaces 50% or more of the burners starting from the date of rule adoption. For small heaters less than 40 MMBTU/hour, achieving 9 ppm with emerging technology is not required until ten years after rule adoption. Alternative B would propose shortening those deadlines so that small boilers would need to meet 5 ppm in six months of 25% or more of the burners being replaced and small heaters would need to meet the 9 ppm within five years of rule adoption (see Table 21 below).

The overall benefits from Alternative B compared to the proposed project will be the same except the benefits will be achieved sooner under Alternative B. All other elements, limits, and deadlines would be the same under Alternative B as is in the proposed project. For the purpose of this socioeconomic analysis, it is assumed that all small heaters are installed and begin operation in 2026 and all small boilers are installed and in operation beginning in 2025.

Table 21: Alternative B Accelerating Future Lower NOx Limit

<table>
<tr><th>Equipment Category</th><th>No. of Units in Category</th><th>Future NOx Limit (ppm)</th><th>Alternative B Implementation Date</th><th>2017 NOx Emissions (tpd)</th><th>NOx Emission Reduction (tpd)</th></tr>
<tr><td>Heaters</td><td rowspan="2">67</td><td rowspan="2">9</td><td rowspan="2">Within 5 years of rule adoption</td><td rowspan="2">0.50</td><td rowspan="2">0.36</td></tr>
<tr><td>< 40 MMBtu/hr</td></tr>
<tr><td>Boilers</td><td rowspan="2">5</td><td rowspan="2">5</td><td rowspan="2">Within 6 months of 25% or more of burners cumulatively being replaced</td><td rowspan="2">0.013</td><td rowspan="2">0.009</td></tr>
<tr><td>< 40 MMBtu/hr</td></tr>
</table>

Alternative C – Less Stringent Proposed Project

Under Alternative C, the implementation period could be extended to provide more time for each facility’s individual projects to take place to achieve the proposed lower NOx limit. Under the proposed project, operators with six or more units complying with Table 1 (of the proposed rule), Table 2 (of the proposed rule), a B-Plan, or a B-CAP in PR 1109.1 have the option to either: a) submit permit applications by July 1, 2023 and achieve the NOx and CO emission limits in Table 1 of PR 1109.1 no later than 36 months after a Permit to Construct is issued, or b) submit an I-Plan to achieve NOx and CO limits under a two- or three-phase timeline. The development of the I-Plan options in Table 6 of PR 1109.1 is a culmination of input from the refineries regarding timeframes and percent reductions; under Alternative C, the time frames could be extended, and percentage reduction targets could be reduced in each phase as presented in Table 22. Both Alternative C and the proposed project would still require the combustion units to meet the proposed NOx emission concentration limit. While the overall quantity of anticipated NOx emission reductions would not be expected to change under Alternative C when compared to the proposed project, more time would be provided for the NO emission reductions to occur, and thus incremental benefit to the environment, are achieved would be delayed.

Table 22: Alternative C (Less Stringent) Implementation Schedule

		Phase I	Phase II	Phase III
I-Plan Option 1	**Percent Reduction Targets**	**70 → 35**	**100 → 50**	**N/A → 100**
	Permit Application Submittal Date	July 1, 2023	January 1, 2027	N/A → January 1, 2031
I-Plan Option 2	**Percent Reduction Targets**	**60 → 30**	**80 → 60**	**100**
	Permit Application Submittal Date	July 1, 2023	January 1, 2025	January 1, 2028
I-Plan Option 3	**Percent Reduction Targets**	**50 → 25**	**100 → 50**	**N/A → 100**
	Permit Application Submittal Date	January 1, 2025	January 1, 2029	N/A → January 1, 2033
I-Plan Option 4	**Percent Reduction Targets**	**50-60 → 30**	**80 → 60**	**100**
	Permit Application Submittal Date	N/A (need to comply by July 1, 2024	January 1, 2025	January 1, 2028
I-Plan Option 5	**Percent Reduction Targets**	**50 → 25**	**70→ 50**	**100**
	Permit Application Submittal Date	July 1, 2022	July 1, 2024	January 1, 2028

Alternative C is less stringent than the proposed project because of an extended implementation schedule of proposed control equipment. Again, NOx limits and the actions to be taken to achieve those limits are expected to be the same under Alternative C as they are for the proposed project. For this analysis, it is assumed that the implementation dates are pushed back by a maximum of two years for all equipment affected in the proposed project.

Alternative D – Limited Start-up, Shutdown, and Malfunction

The proposed project would allow emissions occurring during start-ups, shutdowns, and malfunctions (SSM), pursuant to the definitions in the PR 429.1, to not be considered when determining compliance with the NOx emission limits in PR 1109.1. The proposed project limits the duration of the SSM event as well as limits the severity (e.g., peak NOx concentration in terms of ppm) of the event. While difficult to predict when these SSM events could occur and how impactful they could be, examination of past patterns and researching the duration periods that have been previously required either in the permit conditions or consent decrees helped develop the SSM allowances for the proposed project. Alternative D would reduce the duration of these SSM allowances when compared to the proposed project as outlined in Table 23. This could require facilities to be more diligent in their start-up or shutdown procedures to ensure quick turnarounds and less emission spiking. More attention to maintenance and upkeep of equipment would be needed to reduce the number of malfunction and subsequent equipment downtimes. If additional measures are not taken to reduce the event duration or severity of the peak emissions, under Alternative D, the temporary spike in emissions would need to be incorporated when demonstrating compliance with the NOx limits.

Table 23: SSM Allowances in Proposed Project and Alternative D

Unit	Proposed Project SSM Not to Exceed (hours)	Alternative D SSM Not to Exceed (hours)
Boilers and Process Heaters without NOx Post-Combustion Control Equipment, Gas Turbines, Flares, Vapor Incinerators without NOx Post-Combustion Control Equipment or Castable Refractory	2	2
Boilers and Process Heaters with NOx Post-Combustion Control Equipment, Steam Methane Reformer Heaters, Sulfuric Acid Furnaces	48	24
Steam Methane Reformer with Gas Turbine	60	30
FCCUs, Petroleum Coke Calciner, or SRU/TG Incinerators	120	60

NOx limits and the actions to be taken to achieve those limits are expected to be the same under Alternative D as they are for the proposed project. For the sake of this analysis, it is assumed that there is no change in costs, emission reductions and/or implementation schedule from the proposed project.

Table 24 presents a comparison of the alternatives in terms of annual average cost, NPV (of compliance costs), jobs impacts, and a DCF cost-effectiveness estimate based on a 4% discount and real interest rate. Alternatives A and D have identical NPV, job impacts, and cost-effectiveness to the proposed project given the assumptions made above. Alternative B has a higher NPV given the expedited implementation schedule for small heaters and boilers, resulting in more of the compliance costs to occur in earlier periods. Additionally, job impacts for Alternative B are slightly less positive due to the more stringent implementation timeline. Alternative C has a lower

NPV due to the assumption of an extended implementation schedule for all units, thus allowing for compliance costs to occur in later periods.

Table 24: Average Annual Costs, NPV and Job Impacts by CEQA Alternative

Alternatives	Average Annual Cost (4%) (Millions of 2018$)	NPV (4%) (Millions of 2018$)	Average Annual Job Impacts (2022-2057)	DCF Cost-Effectiveness ($/ton)
Proposed Project	$132.45	$2,336.24	213	$32,698
Alternative A - No Project	$132.45	$2,336.24	213	$32,698
Alternative B - More Stringent	$132.45	$2,465.01	199	$34,570
Alternative C - Less Stringent	$132.45	$2,076.91	225	$29,068
Alternative D - Limited Start-up, Shutdown, and Malfunction	$132.45	$2,336.24	213	$32,698

PUBLIC HEALTH BENEFITS

The South Coast Air Basin is one of only two “extreme” non-attainment areas in the nation that have not reached the federal 8-hour ozone standard. Ground-level ozone, or smog, forms when volatile organic compounds (VOC) photochemically react with nitrogen oxides (NOx) in the presence of sunlight. Ozone exposure can cause immediate, adverse effects on the respiratory system and result in various symptoms such as coughing, throat irritation, chest pain, and shortness of breath. It can also inflame the lining of the lungs, and for asthma patients, it may increase the number and severity of attacks. Long-term impacts of frequent exposure to ozone may lead to permanent lung damage and increase the risk of premature death.

In addition, the South Coast Air Basin remains a serious non-attainment area for the federal PM2.5 standards. Exposure to high levels of PM2.5 have been shown to cause and aggravate cardiopulmonary illnesses, including heart attacks, irregular heartbeat, aggravated asthma, decreased lung function, and increased respiratory symptoms, such as irritation of the airways, coughing or difficult breathing. These outcomes result in increased absences from school and work, hospitalization, and other medical expenses. Exposure to PM2.5 is associated with premature deaths. According to past estimates by the California Air Resources Board, elevated ambient PM2.5 levels result in approximately 4,100 premature deaths annually in the South Coast Air Basin.

Oxides of nitrogen (NOx) is a precursor to both PM2.5 and ozone. Therefore, the reductions in ozone and PM2.5 associated with the proposed rule have the potential to reduce the mortality and morbidity incidences associated with NOx emissions. Public health benefits resulting from compliance with PR 1109.1 are calculated using an incidence per ton (IPT) methodology, developed by the U.S. Environmental Protection Agency.[24,25,26] The IPT methodology is an approximation based on the assumption that the relationship between emissions and adverse health outcomes is linear. Furthermore, the IPT methodology relies on the following assumptions, (1) changes in health incidence are proportional to ambient PM2.5 concentrations; (2) changes in primary pollutant concentrations (PM2.5) are proportional to changes in directly emitted PM2.5; and (3) changes in secondary pollutant concentrations (nitrate PM2.5) are also proportional to changes in precursor emissions (NOx). This final assumption can vary for individual actions due to the complex chemical reactions that occur to create regional pollutants. However, as PR 1109.1 is part of a larger emission reduction strategy, a simplifying assumption is that the health benefits for every ton of NOx reduction in that strategy yields equal benefits.

The public health benefits analysis presented here is based on the proposed project which assumes 74 new SCRs, 15 SCR upgrades, and 76 ULNBs will be installed as a result of PR 1109.1. PR 1109.1 is projected to result in a reduction in NOx emissions of 7 to 8 tpd upon full implementation, however, for the sake of the health benefit analysis, 7 tpd was assumed. The increased use of ammonia associated with the SCR controls creates the potential for ammonia slip. South Coast AQMD staff expects that the installation of 74 new SCRs will result in 0.63 tpd of increased ammonia emissions[27]. Ammonia is also a precursor to PM2.5.

It should be noted that ozone formation violates many of the assumptions underlying the IPT methodology and, as a result, the potential benefits resulting from reductions in ambient ozone concentrations are not quantified in this analysis.

Incidence Per Ton Methodology

Because of the assumed linear relationship between emissions and health outcomes, estimates of reductions in health endpoints resulting from PR 1109.1 can be found by multiplying expected changes in emissions by an IPT factor for each health endpoint.[28] The IPT factors for each health endpoint were calculated using estimated control strategy emissions reductions, air quality modeling in the U.S. EPA's Community Multiscale Air Modeling System (CMAQ), and public health benefits estimation using the U.S. EPA's Environmental Benefits Mapping and Analysis

[24] https://www.ncbi.nlm.nih.gov/pmc/articles/PMC2770129/
[25] https://pubmed.ncbi.nlm.nih.gov/23022875/
[26] https://www.epa.gov/sites/default/files/2018-02/documents/sourceapportionmentbpttsd_2018.pdf
[27] The analysis does not include ammonia slip from the 17 SCR upgrades expected given that SCR upgrades are not projected to result in an increase in ammonia slip above pre-project levels.
[28] https://ww2.arb.ca.gov/sites/default/files/2019-08/Estimating%20the%20Health%20Benefits%20Associated%20with%20Reductions%20in%20PM%20and%20NOX%20Emissions%20-%20Detailed%20Description.pdf

Program – Community Edition (BenMAP-CE) from the 2016 Air Quality Management Plan (AQMP). Total emissions reductions in years 2023 and 2031 resulting from 2016 AQMP control strategies are shown in Table 25 below, while the corresponding reductions in modeled health outcomes in 2023 and 2031 are shown in Table 26 below.

NOx contributes to ambient concentrations of PM2.5 through the formation of nitrate PM2.5. For the sake of calculating contribution to ambient PM2.5 concentrations, it was assumed that each ton of NOx emitted is equivalent to 0.03 tons of directly emitted PM2.5.[29,30]

Regional-specific IPT factors for directly emitted PM2.5 and NOx were calculated using the modeled emission reductions and corresponding health outcomes shown in Tables 25 and 26. A regional-specific IPT factor for directly emitted PM2.5 is calculated by dividing the estimated reduction in incidence of a given health endpoint by the total PM2.5 emission reductions in the years 2023 and 2031.[31] Linear interpolation is then used to generate IPT factors for the remaining years (2024-2030). IPT factors for those years beyond 2031 are simply set equal to the calculated 2031 IPT factor. Regional-specific IPT factors for NOx are calculated similarly after netting out the impacts from directly emitted PM2.5.[32]

As part of the 2015 RECLAIM NOx Shave, South Coast AQMD staff conducted a series of regional simulations to determine the impacts of reducing NOx by the proposed RTC shave while increasing the potential for creating ammonia slip due to increased use of ammonia needed for the operation of SCR controls. Based on the regional air quality modeling simulations run, this analysis assumes that one ton of ammonia is equivalent to 7.36 tons of NOx.[33]

[29] U.S. EPA's February 2018 Technical Support Document, "Estimating the Benefit per Ton of Reducing PM2.5 Precursors from 17 Sectors," estimates the average monetary public health benefits of NOx emissions across all industries is roughly 3% of direct PM emissions (https://www.epa.gov/sites/production/files/2018-02/documents/sourceapportionmentbpttsd_2018.pdf).

[30] The ratio of NOx to PM2.5 could potentially be higher than the 0.03 assumed here. Previous work done on the 2007 AQMP suggested that each ton of NOx emitted is equivalent to 0.1 tons of directly emitted PM2.5 in regards to annual PM2.5 concentrations. A higher NOx to PM2.5 ratio would lead to an increase in IPT factors for NOx and corresponding decrease in IPT factors for directly emitted PM2.5. Given that NOx emission reductions from PR 1109.1 are projected to be significantly greater than directly emitted PM2.5, the 0.03 ratio is used in an attempt to provide a conservative estimate of potential public health benefits.

[31] Reductions in health incidence were estimated for 2023 and 2031 in the 2016 AQMP.

[32] IPT factors also increase over time reflecting the projected increases in population by age class underpinning health effects modeling.

[33] In the analysis, NOx emissions were reduced at RECLAIM facilities by a total of 14 tpd while increasing ammonia slip emissions from the same facilities by 1.63 tpd. The simulations were run for the 2021 draft baseline emissions inventory to estimate the impact when full implementation of the RECLAIM shave was expected to be achieved. The effect of decreasing 14 tpd of NOx resulted in a decrease of annual PM2.5 of approximately 0.7 µg/m3 and the increase in ammonia slip caused a concurrent increase in annual PM2.5 of approximately 0.6 µg/m3. (http://www.aqmd.gov/docs/default-source/Agendas/Governing-Board/2015/2015-dec4-030.pdf)

Table 25: 2016 AQMP Projected Emission Reductions by Pollutant (tpd)

	2023	2031
NOx	124	128
PM2.5	0.22	3.4

Note: Projected emission reductions are average of summer planning period (May 1 to September 30).

Table 26: 2016 AQMP Modeled Reductions in Incidence Due to PM2.5 Exposure

	2023	2031	Average Annual
Premature Deaths Avoided, All Cause			
Long-Term PM2.5 Exposure	1,394	2,716	1,512
Short-Term PM2.5 Exposure[1]	100	194	108
Reduced Morbidity Incidence			
Long-Term PM2.5 Exposure			
Acute Bronchitis	1,039	1,890	1,087
Short-Term PM2.5 Exposure			
Acute Myocardial Infarction, Nonfatal	33	71	38
Asthma Exacerbation (Wheeze, Cough, Shortness of Breath)	23,321	42,780	24,495
Asthma, New Onset (Wheeze)	2,956	5,577	3,151
HA, All Cardiovascular (less Myocardial Infarctions)	164	337	183
HA, All Respiratory (less Asthma)[2]	136	290	155
HA, Ischemic Stroke	79	171	91
HA and ED Visits, Asthma	142	260	149
Lower Respiratory Symptoms	12,268	22,387	12,850
Upper Respiratory Symptoms	24,342	44,720	25,587
Minor Restricted Activity Days[3]	528,869	961,248	552,809
Work Loss Days[3]	91,689	166,826	95,892

* Each health effect represents the point estimate of a statistical distribution of potential outcomes. Please see Appendix 3-B of the 2016 AQMP Final Socioeconomic Report where the 95-percent confidence intervals are reported. Health effects for other years during the period 2017 to 2031 were based on interpolated, as opposed to modeled, air quality changes. The study population of each C-R function utilized can be found in Appendix 3-B of the 2016 AQMP Final Socioeconomic Report.

[1] Premature deaths avoided due to short-term exposure to PM2.5 are likely to partially overlap with those due to long-term PM2.5 exposure. Therefore, the total premature deaths associated with PM2.5 will be lower than simply summing across mortality effects from both short-term and long-term exposure (Industrial Economics and Thurston 2016a; Kunzli et al. 2001).

[2] This is the pooled estimate of two health endpoints: HA, Chronic Lung Disease (less Asthma) (18-64 years old) and HA, All Respiratory (65 or older).

[3] Expressed in person-days. Minor Restricted Activity Days (MRAD) refer to days when some normal activities are avoided due to illness.

These estimated IPT factors were then used to generate estimates of the impacts on health incidence resulting from expected emission reductions resulting from PR 1109.1 compliance.

Table 27 below shows projected changes in NOx and NH3 emissions in tpd for the years 2023 to 2037. PR 1109.1 is expected to result in approximately 31,300 cumulative tons of NOx reductions and an increase of cumulative 2,700 tons of NH3 emissions over the course over the time period from 2023 to 2037.

Table 27: Projected Annual Changes in NOx and NH3 Emissions from 2023 to 2037 (tpd)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033 – 2037*
NOx Decrease	2.40	2.94	3.74	4.53	5.18	5.62	6.14	6.55	6.81	6.90	7.00
NH3 Increase	0.20	0.24	0.30	0.37	0.44	0.48	0.52	0.57	0.60	0.61	0.63

*Emission changes occur at the level reported in each year of the time horizon (2033, 2034,…, 2037)

Using IPT methodology, decreases in NOx emissions will result in positive health benefits (reductions in mortality and morbidity resulting from decreased ambient PM2.5 concentrations), while concurrent increases in NH3 will result in increases in mortality and morbidity due to increased ambient PM2.5 concentrations. Projected reductions of NOx are much larger than the expected increase in NH3, resulting in a net benefit to the South Coast Air Basin. Table 28 shows the corresponding net reductions in health incidence resulting from the emission changes in Table 26 and derived using the estimated IPT factors. Emissions changes are expected to cumulatively result in approximately 370 premature mortalities avoided from long-term and short-term PM2.5 exposure. Additionally, it is expected that PR 1109.1 will result in approximately 6,200 fewer asthma attacks and nearly 21,400 fewer work loss days over the course of the time period from 2023-2037.[34]

[34] Given that the assumed equipment life of SCR and ULNB is 25 years, PR 1109.1 is expected to yield public health benefits well beyond the 2023-2037 time horizon analyzed here. A shorter time horizon was chosen given the uncertainty regarding the value of IPT factors beyond the year 2031.

Table 28: Estimated Net Reductions in Incidence Resulting from Projected Changes in NOx and NH3 Emissions

Endpoint	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033 - 2037*
Premature Deaths Avoided, All Cause											
Long-Term PM2.5 Exposure	10	13	16	19	21	23	25	26	27	27	27
Short-Term PM2.5 Exposure	1	1	1	1	2	2	2	2	2	2	2
Reduced Morbidity Incidence											
Long-Term PM2.5 Exposure											
Acute Bronchitis	7	9	12	14	15	17	18	18	19	19	19
Short-Term PM2.5 Exposure											
Acute Myocardial Infarction, Nonfatal	0	0	0	0	1	1	1	1	1	1	1
Asthma Exacerbation (Wheeze, Cough, Shortness of Breath)	164	213	269	317	348	376	407	414	428	423	425
Asthma, New Onset (Wheeze)	21	27	34	41	45	49	53	54	56	55	55
HA, All Cardiovascular (less Myocardial Infarctions)	1	2	2	2	3	3	3	3	3	3	3
HA, All Respiratory (less Asthma)	1	1	2	2	2	2	3	3	3	3	3
HA, Ischemic Stroke	1	1	1	1	1	1	2	2	2	2	2
HA and ED Visits, Asthma	1	1	2	2	2	2	2	3	3	3	3
Lower Respiratory Symptoms	86	112	141	166	183	197	213	217	224	221	223
Upper Respiratory Symptoms	171	222	281	331	364	393	425	433	448	442	445
Minor Restricted Activity Days	3709	4817	6090	7162	7863	8478	9158	9320	9620	9495	9559
Work Loss Days	643	835	1056	1242	1364	1471	1589	1617	1669	1648	1659

*Health incidence reductions occur at the level reported in each year of the time horizon (2033, 2034,…, 2037)

Valuation of Public Health Benefits

Monetary valuations of all estimated reductions in adverse health outcomes were calculated. The 2016 AQMP calculated the total monetary valuation for each health endpoint by multiplying the number of reduced outcomes for each endpoint by an estimate of the economic value of reducing the associated health risk for each endpoint. For reductions in premature mortalities, an estimate of the value of a statistical life (VSL) was used which came from aggregating reduced health risks. To generate value estimates for morbidities such as hospital admissions or emergency room visits, a cost-of-illness (COI) methodology was typically used. A detailed description of VSL and COI estimates can be found in Chapter 3 of the 2016 AQMP Final Socioeconomic Report. A summary of all monetary values and their associated reference(s) can be found in Appendix 3B of the 2016 AQMP Final Socioeconomic Report.

Staff estimated benefits per ton (BPT) factors for each health endpoint analyzed in the 2016 AQMP. BPT factors are calculated by dividing monetized public health benefits by modelled emission reductions from the AQMP. For example, a NOx BPT factor is calculated by dividing the estimated monetized health benefits of a given health endpoint by the total NOx emission reductions in the years 2023 and 2031. Linear interpolation was used to generate BPT factors for the intermittent years (2024-2030). BPT factors for those years beyond 2031 are simply set equal to the calculated 2031 BPT factor. BPT factors for PM2.5 are calculated similarly.[35] Table 29 below shows annual monetized health benefits over the entire compliance period (2023-2037). For the years 2023 – 2037, estimated discounted total monetized public health benefits is $3.49 billion using a 1% discount rate and $2.63 billion using a 4% discount rate. All dollar figures are in of 2018 dollars.[36,37]

Total discounted public health benefits were calculated over a shorter time period (2022-2037 for health benefits vs 2022-2057 for compliance costs), therefore the NPV for monetized health benefits can't be directly compared to the NPV of compliance costs, but even so, monetized health benefits exceed total costs.

[35] BPT factors increase over time reflecting the projected increases in population by age class and increases in VSL due to projected increases in future incomes.
[36] 2015 dollar figures presented in the 2016 AQMP Final Socioeconomic Report have been adjusted to 2018 dollars using a price inflator of 4.64% based on the October 2020 Marshall & Swift price index (average, all industries).
[37] To avoid double-counting, total monetized public health benefits do not include monetized benefits from reduced mortalities due to short-term PM2.5 exposure.

Table 29: Projected Annual Monetized Health Benefits Resulting from Projected Emission Changes (Millions of 2018 Dollars)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033-2037*
Monetized Health Benefits	$101.5	$134.8	$174.1	$209.2	$234.5	$258.0	$284.4	$295.2	$310.6	$306.6	$308.7

*Benefits a incurred at the level reported in each year of the time horizon (2033, 2034,…, 2037)

Uncertainty in Public Health Benefits Estimation

The IPT methodology employed in this analysis is a proven reduced-form tool to estimate public health benefits and currently utilized by CARB and the U.S. EPA. However, the linearity assumption underpinning the IPT and BPT methodologies employed here is necessarily an approximation, and does not account for complex chemistry, precursor pollutant interactions, and finer-scale geographical effects in the same way that detailed modeling can, as in the 2016 AQMP (using CMAQ and BenMAP). In addition, the relative contribution of NOx to PM2.5 concentrations is subject to uncertainty and may vary by location. Actual changes in PM2.5 concentrations may be higher or lower than what is projected in this analysis. The approximations shown here are consistent with the detailed and holistic 2016 AQMP analysis to the extent that the proposed rule is included as a part of that overall strategy.

THIRD PARTY REVIEW:
DRAFT SOCIOECONOMIC IMPACT ASSESSMENT FOR PROPOSED RULE 1109.1 – EMISSIONS OF OXIDES OF NITROGEN FROM PETROLEUM REFINERIES AND RELATED OPERATIONS

Submitted to:
South Coast Air Quality Management District

Submitted by:

Robert A. Kleinhenz, Ph.D.
Kleinhenz Economics

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INTRODUCTION AND PURPOSE OF THIS STUDY

The South Coast Air Quality Management District (South Coast AQMD or District) is responsible for regulating stationary sources of air pollution in the South Coast Air Basin of Southern California, which includes Los Angeles, Orange, Riverside, and San Bernardino counties, excluding less populated portions of Los Angeles, Riverside, and San Bernardino counties. The agency has regulated emissions at petroleum refineries and related facilities for over three decades. Since 1993, firms in these industries have been subject to the Regional Clean Air Incentives Market (RECLAIM) program, a market-based emissions reduction approach for facilities with Nitrogen Oxide (NOx) and Sulfur Oxide (SOx) emissions greater or equal to four tons per year.

Proposed Rule 1109.1, Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR 1109.1), is intended to facilitate the transition of petroleum refineries and related facilities from the RECLAIM program to a command-and-control regulatory structure. The staff of the South Coast AQMD has conducted a socioeconomic impact analysis of PR 1109.1, the results of which are contained in the report, "Draft Socioeconomic Impact Assessment for Proposed Rule 1109.1–Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations," hereafter referred to as the Socioeconomic Impact Assessment Report or the SIA. The South Coast AQMD has engaged Kleinhenz Economics to serve as an independent reviewer of the socio-economic impact analysis contained in the SIA.

The present report summarizes the findings of the independent, third-party review of the SIA Report, as conducted by Kleinhenz Economics. The review examined the overall contents of the SIA Report with particular attention devoted to the data, assumptions, modeling, and the analytical results contained in the report.

GENERAL COMMENTS ON REPORT

The SIA Report includes the following components:

1. Describes the regulatory history and legislative mandates pursuant to the affected industries
2. Identifies affected industries, providing characteristics of these industries
3. Describes the operating assumptions used for the economic impact analysis of PR 1109.1
4. Evaluates the economic impact of PR 1109.1 on employment and the regional economy
5. Evaluates the potential impact of PR 1109.1 on emissions reduction and health benefits
6. Evaluates cost-effectiveness of alternatives to PR 1109.1

This third-party review is an assessment of items 3, 4, and 5 above, specifically the methodology, data and assumptions, and results associated with the economic impact analysis and health benefit calculations of PR 1109.1.

STRENGTHS AND WEAKNESSES OF THE STUDY

In general, the approach adopted in the SIA is reasonable, as are the results in terms of costs, jobs impact, and health benefits. The strengths of the study are as follows:

- There is a known number of affected firms in the industries affected by PR 1109.1, and the number of industries and firms is relatively small.
- Given the length of time, the affected industries have been subject to air quality regulations, there is substantial information on both regulation and compliance costs.
- There is a well-established methodology for evaluating the economic impact of PR 1109.1 in terms of data, assumptions, and modeling.
- When policy changes are evaluated for their economic impact, input prices are typically assumed to be constant. This may be a reasonable assumption for most policy analysis, but PR 1109.1 is expected to generate downstream changes in fuel prices. Because the impact on input prices and fuel prices is of interest, the study extends its policy analysis by estimating impacts of PR 1109.1 on downstream input prices.
- Furthermore, in order to quantify the impact of PR 1109.1 on consumers and businesses in the South Coast Region, the South Coast AQMD commissioned a separate analysis that estimates the impact of PR 1109.1 on fuel prices, demand, and consumption in the South Coast region, which estimated a negligible impact on fuel prices.[38]

The SIA uses the REMI model to estimate the ripple or multiplier effect of capital expenditures and operating outlays associated with PR 1109.1 compliance. Of particular interest is the extent to which PR 1109.1 triggers job creation in the local economy that might otherwise offset potential job losses resulting from implementation of PR 1109.1 measures. In principle, industries that may experience job creation may include construction, maintenance, and to the extent that it is fabricated locally, emissions control equipment itself. SIA report Table 17 shows that job impacts in the affected industries will be minimal, that there will be substantial job generation in the construction industry, and that other industries will experience minimal job changes. This is expected, given that the refining and related industries subject to PR 1109.1 are capital intensive (less than 2,000 positions in a region with nearly 12 million jobs), and that construction costs associated with PR 1109.1 implementation account for 80% of total installed cost (TIC) estimates.

In all, the known features of the industry, the availability of historical industry and compliance data, and the study's enhancements to existing and well-established impact methodology presumably increase the reliability of the estimated equipment, compliance, and administrative costs that are associated with PR 1109.1.

The following elements in the study may require attention:

- Assumed target reduction in emissions to 7.83 tons per day
- The assumed inflation rate factor used in cost estimates

[38] "The Impact of PR 1109.1 on Fuel Prices and Demand in the South Coast," by E. Muehlegger (2021).

- The choice of discount rate
- The assumed lifespan of emissions control equipment across the affected industries

Each of these elements will be analyzed for their implications regarding projected compliance costs, estimated job impacts, and estimated health benefits associated with PR 1109.1.

<u>Choice of Target Reduction in Emissions</u>

The SIA established the target reduction in emissions as follows.

> The 7.83 ton per day emission reduction estimate represents staff's assumption regarding the units that would qualify to meet the Table 2 conditional limits with all other units meeting the Table 1 emission limits. (SIA v.7, p. 15)

For the purpose of the SIA, the emission reduction target is determined outside the analysis by the South Coast AQMD rules staff, hence is parametrically given in the SIA. Still, there is no context 1-1
for this assumed target. While it would be excessive to include the referenced tables and provide a detailed discussion of their contents and relevance to the SIA, the SIA should briefly and concisely explain the rational for this target.

Furthermore, as a part of establishing the validity of the results contained in the SIA, it may be advisable to discuss within the SIA: a) whether the assumed emissions reduction is subject to modification, and b) if so, whether sensitivity analysis of results to changes in the assumed emission reduction target be considered. Minimally, there should be some mention of the extent to which the results of SIA are sensitive to the assumed or other values of emission reduction.

<u>Inflation Factor Used</u>

As a part of the determining the economic impact of PR 1109.1, various costs must be estimated, including estimates of total installed cost (TIC) for the equipment, costs of operations and maintenance (O&M), and costs administrative activities. These costs are incurred over a period of time which is assumed to be 25 years across all of the affected industries. Due to the unique specifications associated with retrofitting existing facilities with proposed pollution control equipment, costs were generally obtained directly from the refiners and supplemented as needed by information from other sources. 1-2

For the purpose of modeling the economic impact of PR 1109.1 in the REMI framework, all input costs must be adjusted to a common baseline time period. The year 2018 was selected as the base year for the analysis, and as stated in the report, "staff conservatively escalated all costs at 4% annual inflation rate to the 2018 dollar year" (SIA v.7, p. 14). Further, it is asserted that is a "conservative" assumption.

It is essential for the integrity of the impact analysis to use the appropriate inflation rate and substantiate its applicability to the task at hand. In that vein, the study should explain the rationale for the assumed inflation rate, whether it be 4% as shown in the study or any other rate to be used.

In fact, a 4% inflation rate seems high, given that most gauges of inflation have rarely exceeded three percent in recent memory. Therefore, one might compare the assumed inflation rate with commonly cited inflation rates such as the CPI or GDP deflator, and explain why the assumed rate aligns with, exceeds, or falls short of the typical measures. This gives the reader a point of reference to better understand the inflation adjustments that were made in the study.

1-2 cont.

Finally, use of the term “conservatively” bears some elaboration, As described by staff, potential cost estimates will fall in a range that depend on the underlying assumptions used. There is a preference to use cost estimates in the high end of the range so as to avoid underestimating the costs to be borne by the affected industries. In this sense, “conservative” should be interpreted as the *likely high cost scenario* that has been identified from the range of possible cost scenarios. A clarification along these lines would help the reader to better comprehend how a given cost estimate was selected.

<u>Choice of Discount Rate</u>

As stated in various sections of the report, the SIA is predicated upon assumed discount rates of 1% and 4%. Earlier versions of the SIA reported TIC estimates under assumed discount rates of both 1% and 4%, but SIA v.7 presented summary results for each of the rates scenarios (Table 15, SIA v.7, p. 28), limiting reporting of detailed results for the eight equipment category exclusively to the 4% scenario. Health benefits are estimated using both discount rates.

No discussion is provided to establish the validity of the discount rates that were used in the analysis, nor is there any discussion of how sensitive the results of the analysis may be to different discount rates. Furthermore, as a part of establishing the validity of the results contained in the SIA, it is recommended that:

- The SIA include a general description of how discount rates affect calculated net present value (NPV), and how higher discount rates imply lower present values of future costs and benefits while lower rates imply higher present values. 1-3
- Justification be provided for the rates chosen in a concise, high-level discussion. This may include discussion of whether the same or different discount rates ought to be applied to NPV of benefits and NPV of costs.
- Address the matter of sensitivity analysis as it relates to changes in the discount rate. If the results are generally not sensitive to changes in the discount rate, a statement to that effect is sufficient. Similarly, if “the industry standard” implies a specific rate or range of rates are typically used in impact studies such as this, a statement to that effect accompanied by a brief explanation to describe the rationale behind the industry standard ought to be satisfactory.
- Consider whether the results of the analysis should be aligned so that the benefits and costs can readily be compared under the same assumed discount rate.

Assumed Lifespan of Emissions Control Equipment

The SIA analysis eight categories of equipment in terms of capital costs, operations and maintenance costs, and total costs. For each category, it is uniformly assumed that the lifespan of the equipment is 25 years. This assumption is useful because one can more easily align future costs across equipment categories for comparison purposes. Still, one must explain whether it reasonably represents actual lifespans of the equipment to be regulated under PR 1109.1.

It seems plausible that different types of equipment have different estimated lifespans, depending on their application, the frequency of use, and other characteristics of the equipment, and conditions in their operating environment. Even if one can reasonably assume a uniform lifespan for the equipment, one must ask whether a 25-year horizon is appropriate. Finally, one must consider how sensitive the results are to reasonable changes in the time horizon, for example, whether it is cut to 20 years or increased to 30 years. 1-4

Justification for such an assumption should be discussed in the report. If these details are discussed elsewhere in source material related to PR 1109.1 or in a companion report, a high-level summary of this background information and the rationale behind a 25-year lifespan would enhance the validity of the SIA findings.

CONCLUSION

Any economic analysis relies heavily on working assumptions. Assumptions that are reasonable and are supported by sufficient background information increase the validity of the economic analysis and its implications. In the absence of sufficient background information, questions arise about the reliability of the results and their applicability. The above recommendations should serve to reinforce the validity of the SIA and its contents. 1-5

Finally, it is suggested that the South Coast AQMD include in the SIA a discussion of the relative costs and benefits of PR 1109.1 in comparison to other similar mitigation measures, to better understand more broadly, fundamentally, and transparently the "return on investment" associated with a dollar spent on PR 1109.1 versus a dollar spent on other mitigation measures.

South Coast AQMD Responses to Kleinhenz Economics Review of PR 1109.1 Draft Socioeconomic Impact Assessment (SIA)

Response to Comment #1-1

The SIA states that PR 1109.1 is expected to result in 7 to 8 tpd in NOx emission reductions. The 7.83 tpd emission estimate used in the SIA cost analysis reflects the conservative assumption that all equipment eligible to meet the conditional limits outlined in Table 2 of the proposed rule will do so, and all remaining equipment not eligible to meet conditional limits are assumed to meet the limits outlined in Table 1. The emission limits outlined in the proposed rule are the result of a Best Available Retrofit Control Technology (BARCT) assessment for combustion equipment located at all sixteen affected facilities. Emissions reductions may differ slightly in reality, as facilities have been granted significant compliance flexibility through the use of the B-Cap approach, which allow facilities to meet BARCT emissions target in aggregate. A footnote (#5) has been added to the Final SIA that further clarifies the emission reduction estimate and an additional footnote (#6) has been added that directs readers to the Staff Report for more detailed information on the B-Cap approach.

The 7.83 tpd in NOx reductions is a conservative estimate and represents a "high-cost" scenario. It is possible that facilities will meet their compliance obligations through the use of the B-Plan and B-Cap options at a cost that is lower than what is assumed in this report. A footnote (#7) has been added to the Final SIA explaining that the assumed 7.83 tpd NOx reduction estimate is conservative and based on a high-cost scenario.

Response to Comment #1-2

A footnote (#9) has been added to the Final Socioeconomic Impact Assessment explaining that the "conservative" assumption or estimate should be interpreted as resulting in a high-cost scenario that has been identified from the range of possible cost scenarios. The footnote also compares the 4% inflation factor used to recent estimates from the CPI and GDP deflator:

> The use of the 4% inflation factor is a conservative estimate, resulting in a higher cost estimate. For comparison, the average increase in the Consumer Price Index, or CPI, over the period from 2011 to 2020 is 1.73% (https://fred.stlouisfed.org/series/CPALTT01USA657N) and the average increase in the GDP deflator over the same time period is 1.7% (https://fred.stlouisfed.org/series/A191RI1A225NBEA). In addition, the average annual increase in the Marshall & Swift Cost Index is 1.6% over the time period 2011 to 2020.

Response to Comment #1-3

A footnote (#12) has been added providing a high-level justification for the choice of discount rate. An additional footnote (#13) has been added to the Final SIA describing how the choice of discount rate affects the calculated net present value, or NPV. A footnote (#18) has also been added discussing the sensitivity of the reported average annual costs to the choice of discount rate has been added.

A sentence comparing cost and benefits has been added to the end of the Public Health Benefits sections of the Final SIA. Specifically, "Total discounted public health benefits were calculated over a shorter time period (2022-2037 for health benefits vs 2022-2057 for compliance costs), therefore the NPV for monetized health benefits can't be directly compared to the NPV of compliance costs, but even so, monetized health benefits exceed total costs."

Response to Comment #1-4

A footnote (#10) has been added to the Final SIA that includes a justification of the assumption of a 25-year equipment life for SCRs. An additional footnote (#11) has also been added that explains the sensitivity of the cost estimates to the equipment life assumed.

Response to Comment #1-5

The key assumptions of the analysis including the installation schedule and the facility-specific costs were included in the 'Methodology of the Socioeconomic Impact Assessment' section of the SIA. In addition, as mentioned in the comments above, staff has added additional footnotes further explaining our assumptions regarding the emissions reduction estimate, the inflation factor used, choice of discount rate, and the assumed lifespan of the equipment.

A new section has been added to the Final SIA ("Comparison of Cost-Effectiveness with Recently Adopted RECLAIM Landing Rules") that discusses the relative costs and benefits of PR 1109.1 in comparison to other similar mitigation measures.

MEMORANDUM | 6 SEPTEMBER 2021

TO Shah Dabirian, Ryan Finseth; South Coast Air Quality Management District (SCAQMD)

FROM Henry Roman, IEc

SUBJECT Review of Incidence per Ton Health Benefits Analysis for Proposed Rule 1109.1

INTRODUCTION

The South Coast Air Quality Management District (SCAQMD) is developing Proposed Rule (PR) 1109.1, the purpose of which is to protect human health by reducing emissions of nitrogen oxides (NO_x) from petroleum refineries and related operations. The South Coast Air Basin is currently in non-attainment status with respect to the federal National Ambient Air Quality Standards (NAAQS) for both fine particulate matter ($PM_{2.5}$) and ground-level ozone. A substantial literature base for both pollutants, as documented in U.S. EPA's recent Integrated Science Assessments, associate exposure to these pollutants with adverse health impacts. $PM_{2.5}$ exposure is linked to effects on respiratory and cardiovascular health; ozone is linked to adverse effects on respiratory health; and both can increase the risk of premature death.[39,40] Since NO_x emissions are a precursor to the formation of both ozone and $PM_{2.5}$, rules such as PR 1109.1 are part of SCAQMD's region-wide air quality management plan to help bring the air basin into compliance with the federal standards, and will be expected to result in health benefits to the exposed population in the basin. This particular PR is also anticipated to increase emissions of ammonia (NH_3), another $PM_{2.5}$ precursor, as a result of the use of selective catalytic reduction (SCR) units for emissions control. A proper accounting of the benefits of this PR must address both impacts to identify the net effects on public health.

To support the development of PR 1109.1, SCAQMD conducted a socioeconomic analysis that includes an assessment of the expected net impact on human health resulting from (1) the expected reductions of NO_x emissions; and 2) the expected increase in NH_3 emissions from refineries in the basin.[41] The purpose of this memorandum is to review SCAQMD's human health benefits analysis for PR 1109.1, which employs a reduced-form approach that applies previously estimated impacts of similar rules expressed as a incidence per ton (IPT) of emissions reduced.

The remainder of this memo proceeds as follows. We first provide a summary of SCAQMD's approach to the health benefit analysis and then present our review of that approach for PR 1109.1, considering the reasonableness of applying reduced form methods both generally and in this instance, the specific methods and assumptions SCAQMD employed in this analysis, and recommendations to consider that may help improve the approach in future. We emphasize that this review focuses only on the human

[39] U.S. EPA. Integrated Science Assessment (ISA) for Particulate Matter (Final Report, Dec 2019). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-19/188, 2019.

[40] U.S. EPA. Integrated Science Assessment (ISA) for Ozone and Related Photochemical Oxidants (Final Report, Apr 2020). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-20/012, 2020.

[41] South Coast Air Quality Management District. 2021. *Draft Socioeconomic Impact Assessment for Proposed Rule 1109.1 — Emissions of Oxides of Nitrogen for Petroleum Refineries and Related Operations*, September.

health analysis of $PM_{2.5}$ included in SCAQMD's socioeconomic analysis of the rule, and not any of the other analyses. In addition, we did not review the illustrative analysis of ozone health impacts, which are less amenable to reduced-form approaches because of ozone's complex chemistry.

OVERVIEW OF SCAQMD APPROACH

SCAQMD employs a reduced-form approach for estimating the health impacts of this PR, which is proposed to help implement one control measure within its overall 2016 air quality management plan (AQMP). A reduced-form method uses tools or data based on less complex representations of the time- and resource-intensive photochemical air quality models (e.g., CMAQ) and health impact models (e.g., BenMAP-CE) used for analysis of large-scale rulemakings. Though less sophisticated, these reduced-form models are typically based on previous runs or series of runs of the "full-form" suite of modeling tools.

In this case, SCAQMD employs an IPT method based on a benefit-per-ton (BPT) method originally developed by U.S. EPA. This method assumes a constant, linear relationship between each ton of a pollutant (and its precursors) emitted and the expected change in the incidence of premature death or other adverse health impacts in the exposed population. Other stated assumptions include:

- Changes in health incidence are proportional to ambient $PM_{2.5}$ concentrations;
- Changes in primary pollutant concentrations are proportional to changes in directly emitted $PM_{2.5}$; and
- Changes in secondary $PM_{2.5}$ are proportional to changes in precursor emissions (NO_x, NH_3).

SCAQMD develops its IPT estimates by dividing the full-scale benefits analysis results in 2023 and 2031 from its Socioeconomic Analysis of the 2016 AQMP by the total modeled reductions in directly emitted (Primary) $PM_{2.5}$ and NO_x associated with the AQMP. Because NO_x contributes to $PM_{2.5}$ through the secondary formation of nitrate $PM_{2.5}$, SCAQMD expresses NOx reductions as a primary $PM_{2.5}$ equivalent. It does so by applying a ratio of 0.03 tons of primary $PM_{2.5}$ per ton NO_x emitted, based on an average of the ratio of U.S. EPA's previously estimated BPT values for NO_x and primary $PM_{2.5}$.

SCAQMD does not develop a specific IPT value for NH_3 emissions, which also lead to secondarily formed $PM_{2.5}$ particles. Instead, they rely on the results of regional air quality modeling simulations previously run for the 2015 RECLAIM NOx Shave rule to estimate the relative impact of NH_3 versus NO_x in generating secondary PM. Based on that modeling, they estimate that one ton of ammonia is equivalent to 7.36 tons of NO_x. Estimated IPT values for NH_3 are negative, denoting negative health benefits associated with increasing NH_3 emissions.

SCAQMD also develops BPT values by multiplying each of the IPT values by the corresponding dollar value per case used in the 2016 AQMP socioeconomic analysis. For benefit years between 2023 and 2031, they apply a linear interpolation for both IPT and BPT. For years beyond 2031, they fix the IPT/BPT estimates at 2031 levels.

REVIEW OF SCAQMD HEALTH BENEFIT ANALYSIS FOR PR 1109.1

We find the approach applied by SCAQMD produces a reasonable first approximation of benefits, though it would benefit from additional characterization of uncertainty to test sensitivity to some of its 1-1 assumptions. Longer-term, it would benefit from analysis of modeling informed by source apportionment that could support refined IPT estimates that are more source-specific and geographically specific. Despite the uncertainties, the authors have in many cases opted to use conservative assumptions in their analysis, reducing the likelihood that they have overestimated benefits. Below we discuss the factors we considered in our review. 1-1 cont

USE OF IPT/BPT FOR BENEFITS ANALYSIS

There is considerable precedent for the use of reduced form tools for air quality benefits analysis, including IPT/BPT. There are a growing set of options available for conducting streamlined air quality and health modeling steps of an analysis where time, resources, and/or data gaps make full-scale modeling challenging. As noted by SCAQMD, the BPT method was first developed by U.S. EPA, and EPA has applied BPT estimates to conduct analyses for the 2011 Mercury and Air Toxics Standards and 2011 Ozone Cross-state Air Pollution Rule.[42,43] This approach has also been used in benefits analyses by CARB.[44] Other reduced tools such as InMAP and AP2 have been used in peer reviewed air quality health benefits analyses.[45]

IPT/BPT values are a function of several factors – the nature of the emissions and their effect on the pollutant of interest (e.g., primary emissions versus precursor emissions); spatial distribution of emission sources, local geography and meteorology; and the size and location of populations potentially exposed. As a result, the ideal IPT/BPT values would be ones that are both source- and location-specific. The SCAQMD approach is specific to the South Coast air basin but is not source-specific and thus reflects an average IPT effect across all sources. On the other hand, U.S. EPA's 2018 published BPT values include refinery-specific estimates, but they are averaged across the entire nation and thus would fail to capture the specifics of refinery issues in this region.[46] EPA also has reported source-specific BPT values for PM-related effects of NO_x and NH_3 emissions by source categories based on modeling in the San Joaquin valley in Fann et al 2009; these estimates are a bit older, however.[47] Given their recency, geographic 2-2

[42] US EPA. 2011. Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards. Research Triangle Park, NC, Office of Air Quality Planning and Standards. US Environmental Protection Agency. December 2011. EPA-452/R-11-011. https://www3.epa.gov/ttnecas1/regdata/RIAs/matsriafinal.pdf.

[43] US EPA. 2011. Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States. Research Triangle Park, NC, Office of Air and Radiation. US Environmental Protection Agency. June 2011. https://www.epa.gov/sites/production/files/2017-07/documents/epa-hq-oar-2009-0491-4547.pdf.

[44] https://ww2.arb.ca.gov/sites/default/files/2019-08/Estimating%20the%20Health%20Benefits%20Associated%20with%20Reductions%20in%20PM%20and%20NOX%20Emissions%20-%20Detailed%20Description.pdf

[45] See for example Tessum, C.W., Apte, J.S., Goodkind, A.L., Muller, N.Z., Mullins, K.A., Paolella, D.A., Polasky, S., Springer, N.P., Thakrar, S.K., Marshall, J.D. and Hill, J.D., 2019. Inequity in consumption of goods and services adds to racial–ethnic disparities in air pollution exposure. Proceedings of the National Academy of Sciences, 116(13), pp.6001-6006; and Jaramillo, P. and Muller, N.Z., 2016. Air pollution emissions and damages from energy production in the US: 2002–2011. Energy Policy, 90, pp.202-211.

[46] https://www.epa.gov/benmap/sector-based-pm25-benefit-ton-estimates

[47] Fann, N., Fulcher, C.M. and Hubbell, B.J., 2009. The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution. Air Quality, Atmosphere & Health, 2(3), pp.169-

specificity, and reflection of fine scale local photochemical modeling for the 2016 AQMP, the SCAQMD IPT values are a reasonable choice. SCAQMD should consider, however conducting sensitivity analysis with appropriate estimates from the Fann et al study, given that it would provide source- and geography-specific, if imperfectly matched, estimates. 2-2 cont

KEY ASSUMPTIONS IN SCAQMD ANALYSIS

Regarding the key assumptions noted by SCAQMD, the assumption of linearity between changes in $PM_{2.5}$ and health effects generally holds for concentrations in the concentration ranges observed in the South Coast Basin based on the weight of evidence in the U.S. EPA ISA; recent studies such as the Integrated Exposure Response model or the Global Exposure Mortality Model that have fit non-linear functions show changes in the dose-response slope occurring at higher concentrations than those in this analysis.[48,49] The proportionality of $PM_{2.5}$ with primary emissions is also a reasonable assumption, given the lack of complex chemistry involved. In a limited set of policy analyses performed by IEc using various reduced form tools, some tools did show a tendency to predict higher NO_x related PM benefits than those generated using CMAQ-based measurements; however, the BPT estimates generated using the U.S. EPA method tended to be in better agreement with the CMAQ estimates.[50] Future analyses may wish to explore this area further. 2-3

The assumption that NO_x contributes 0.03 of a ton of directly-emitted PM is based on an average of the NO_x / Primary $PM_{2.5}$ BPT ratio across all emitting sectors from the published U.S. EPA 2018 values. My calculation of this ratio from U.S. EPA's BPT for refineries specifically is closer to 0.21. Alternatively, a quick analysis using U.S. EPA's COBRA model for the four counties in the South Coast air basin suggests a BPT ratio of NO_3/Primary $PM_{2.5}$ of approximately 0.1, similar to the value SCAQMD notes in footnote 7.[51] The value used of 0.03 seems a reasonably conservative choice that is unlikely to overstate benefits, but an expanded sensitivity analysis spanning 0.21 to 0.1 would aid in characterizing uncertainty in this parameter.

IEc cannot directly comment on the air quality modeling underlying the assumption that one ton of NH_3 emissions in the air basin is equivalent to 7.36 tons of NO_x, as this is outside of IEc's area of expertise. However, we did search for other empirical data points for comparison. We found that NH_3 BPT can differ depending on the source category. The Fann et al, 2009 BPT estimates for San Joaquin valley show quite similar BPT estimates for non-EGU NO_x emissions ($28,000) and area source NH_3 emissions ($36,000), as compared to mobile source NH_3 ($140,000). Dedoussi and Barrett also found larger relative 2-4

176.

[48] Burnett, R.T., Pope III, C.A., Ezzati, M., Olives, C., Lim, S.S., Mehta, S., Shin, H.H., Singh, G., Hubbell, B., Brauer, M. and Anderson, H.R., 2014. An integrated risk function for estimating the global burden of disease attributable to ambient fine particulate matter exposure. Environmental health perspectives, 122(4), pp.397-403.

[49] Burnett, R., Chen, H., Szyszkowicz, M., Fann, N., Hubbell, B., Pope, C.A., Apte, J.S., Brauer, M., Cohen, A., Weichenthal, S. and Coggins, J., 2018. Global estimates of mortality associated with long-term exposure to outdoor fine particulate matter. Proceedings of the National Academy of Sciences, 115(38), pp.9592-9597.

[50] Industrial Economics, Incorporated., 2019. Evaluating Reduced-form Tools for Estimating Air Quality Benefits. Prepared for EPA's Office of Air Quality Planning and Standards. September.

[51] U.S. EPA CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA); https://www.epa.gov/cobra

benefits nationwide of NH_3 versus NO_x per unit mass reduced among mobile sources. However, for industrial sources, they found that NH_3 contributed only about twice as much as NO_x nationwide to population exposure.[52] Given the limited points of comparison, this is an area that would benefit from further investigation, but compared to current relevant data, the SCAQMD assumption appears reasonable, and potentially conservative, from a benefits perspective. 2-4 cont

The method used to grow the IPT/BPT estimates over time is reasonable; given that it is based on estimates from the 2016 AQMP analysis that include both projections for population and income growth in its 2023 and 2031 estimates, the linear interpolation procedure effectively incorporates these growth factors in the intervening years. Fixing the IPT/BPT estimates post 2031 is a suitably conservative choice reflecting additional uncertainty extrapolating beyond those two modeled years. 2-5

The spreadsheet models used to calculate the IPT/BPT values were well-organized, clear, and free of errors. For context, we compared SCAQMD's BPT value for mortality impacts of long-term exposure against the BPT values reported in Fann et al, 2009 for other large cities. Converting the two estimates into common units, the SCAQMD estimate for Primary $PM_{2.5}$ appeared to be about 2.5 times larger than the comparable estimates from Phoenix, Arizona. This difference does not seem unreasonable, given that the population of Los Angeles is roughly 2.5 times larger than Phoenix. The BPT values in the two cities could also be affected by relative differences in baseline mortality rates and geographic patterns of exposure between the two cities, which we did not investigate, but it seems likely that the population difference would be the major contributor to the observed difference.

RECOMMENDATIONS FOR FUTURE WORK

If SCAQMD intends to continue applying the IPT approach in the future, potential areas for refinement include the following:

- **Sensitivity Analysis**. Given the assumptions inherent in a reduced-form approach such as IPT, generation of alternative estimates that assess the sensitivity of the benefits model to changes in those assumptions would provide the reader with a better sense of the robustness of the results.
- **Source-apportionment based IPT.** Following the U.S.EPA model, developing a set of BPT values for the South Coast basin that are based on local-scale photochemical modeling of the air quality impacts of emissions from particular source categories will help SCAQMD better tailor its IPT analyses to the sources impacted by future rules. 2-6
- **Estimation of secondary $PM_{2.5}$ from precursors using reduced form tools.** Given the importance of NO_x reductions to the AQMP, and the rapidly evolving field of reduced-form air quality modeling, the ability of these tools to estimate PM from precursors such as NO_x and NH_3 will continue to improve. Monitoring these developments will help SCAQMD to evaluate the relative strengths of the IPT approach versus use of reduced-form air models in future assessments.

[52] Dedoussi, I.C. and Barrett, S.R., 2014. Air pollution and early deaths in the United States. Part II: Attribution of PM2. 5 exposure to emissions species, time, location and sector. Atmospheric environment, 99, pp.610-617.

South Coast AQMD Responses to Industrial Economics, Incorporated (IEc) Review of PR 1109.1 Public Health Benefits Assessment

Response to Comment #2-1

Thank you for your thorough and detailed comments. In the future, we hope to generate more pollutant-specific IPT and BPT factors during the air quality and health effects modeling of the 2022 AQMP.

Response to Comment #2-2

The calculated IPT and BPT factors are linearly dependent on the size of the affected population. Staff firmly believes that attempting to use the BPT factors estimated for the San Joaquin Valley (Fann study) and the US (EPA study) would not result in reasonable estimates of public health benefits resulting from PR 1109.1 given the high population density of the South Coast Air Basin. The suggested use of industry-specific or more specific geographic IPT and BPT factors (county-level) would enhance the analysis and may be considered in future air quality modelling scenarios.

Response to Comment #2-3

The assumption that NO_x contributes 0.03 of a ton of directly-emitted PM is used when calculating the region-specific IPT and BPT factors from the modeled emission changes and the resulting public health benefits generated from the 2016 AQMP. This assumption is based on the ratio of the EPA's IPT/BPT factors for NOx and PM2.5 across all industries. The modeled emission reductions in the 2016 AQMP were generated across all industries/sources, and were not refinery-specific. The suggested use of refinery-specific IPT and BPT factors using a 0.021 trading ratio may not be practical given that the 2016 AQMP did not model the air quality impacts resulting from refineries in isolation. Alternatively, the use of the 0.1 NOx to direct PM2.5 trading ratio would result in much higher (greater than 3x) IPT and BPT factors for NOx and correspondingly lower IPT and BPT estimates for direct PM2.5 when compared to the IPT and BPT factors under the 0.03 trading ratio assumption. Given that PR 1109.1 emission reductions are primarily from NOx, the corresponding public health benefits using the 0.1 trading ratio would be larger than those reported in the SIA. Therefore, the 0.03 trading ratio assumption can be considered as a more conservative approach.

Response to Comment #2-4

Staff will consider generating IPT and BPT factors for NH3 and additional pollutants beyond NOx and PM2.5 using CMAQ and BenMap in future Air Quality Management Plans.

Response to Comment #2-5

Thank you for commenting on the methodology used to estimate the region-specific IPT and BPT factors. South Coast AQMD staff have made a concerted effort to use conservative assumptions when quantify public health benefits.

Response to Comment #2-6

Staff anticipates making enhancements to the IPT and BPT calculations during future AQMP processes, including potentially generating industry- and geography-specific IPT factors. In addition, staff will continue to monitor the developments in the field of reduced-form air quality modeling.

APPENDIX A: THE IMPACT OF PROPOSED RULE 1109.1 ON FUEL PRICES AND DEMAND IN THE SOUTH COAST AQMD REGION

The Impact of PR 1109.1 on Fuel Prices and Demand in the South Coast AQMD Region

Erich J. Muehlegger, Ph.D.

July 30, 2021

1 Executive Summary

This report estimates the impacts of South Coast Air Quality Management District's ("South Coast AQMD") Proposed Rule ("PR") 1109.1 on the prices of and demand for refined products in the South Coast AQMD region. Central to this exercise is an evaluation of the pass-through of costs by refineries in the Los Angeles area. That is, when refinery costs rise, are refineries able to commensurately increase the prices of refined products? Or, does competition from refineries outside of Los Angeles limit local refiners' ability to raise prices? This report first discusses the economic concept of pass-through and how it relates to the specific details of the refined product markets in the South Coast AQMD region. It provides two sources of evidence that speak to the appropriate pass-through rate for the compliance costs associated with PR 1109.1. Finally, it translates the pass-through estimates into impacts on prices and demand for refined fuels.

The main conclusions of the report are four-fold.

- First, under normal conditions, the market for refined products in Southern California is largely served by local refineries, reflective of the unique requirements of refined fuels in the South Coast AQMD region and the lack of pipeline delivery infrastructure into the region.

- Second, refineries from outside the region (and outside the United States) play an important role in the market by: (1) competing with Los Angeles refineries in markets served by both (e.g., Phoenix), and (2) delivering product to Los Angeles at times when prices rise (e.g., after the Torrance refinery fire.) This competition tends to moderate prices and limit the ability of Los Angeles refiners to pass-through production costs into spot prices. A quantitative examination of the pass-through of credit prices is consistent with a moderate pass-through rate.

- Third, scaling annual operational costs of compliance on a per-gallon basis, average costs across the five major refineries in Los Angeles County are roughly 0.2 cents per gallon. Including annualized capital costs associated with PR 1109.1, the per-gallon costs average 2.5 cents per gallon.

- If the costs are fully-passed onto retail price, the per-gallon cost increase would imply a retail price increase of less than one percent, even with the inclusion of annualized capital costs. But, using a pass-through estimate (30%) that reflects the competition faced by refineries in the South Coast AQMD region, the impact on retail prices would be more modest, totalling less than one cent per gallon, even if annualized capital costs are included. As the price effects are small, the effect on overall fuel consumption would be negligible.

Contents

2 Statement of Qualifications

My name is Erich J. Muehlegger. I am an Associate Professor of Economics at University of California, Davis and a research associate of the National Bureau of Economic Research. Prior to my employment at University of California, Davis, I was an Assistant Professor and Associate Professor of Public Policy at Harvard Kennedy School and received my Ph.D. in Economics from Massachusetts Institute of Technology in 2005. The statements expressed herein are mine alone, and do not reflect the views of the institutions with whom I am or have been affiliated.

In my research, I have specialized in the impact of regulation and taxes on the decisions of firms and consumers in energy markets. My dissertation examined the price impact of "boutique gasoline blends" in the late 1990's including California's blend of reformulated gasoline. Since receiving my doctorate, I have authored or co-authored seventeen peer-reviewed papers, many of which examine how regulations, taxes or input costs are passed-through by firms onto customers in energy markets. These papers have been published in top Economics journals, including *Journal of Political Economy*, *Review of Economics and Statistics*, *American Economic Journal: Economic Policy*, and *Journal of Public Economics*. My CV is attached as Appendix B.

3 Introduction

South Coast Air Quality Management District ("South Coast AQMD") staff is developing a new rule, the goal of which is to reduce NOx emissions associated with refinery operations in the South Coast AQMD region (Los Angeles, Orange, Riverside, and San Bernardino counties). The rule is known as Proposed Rule 1109.1-Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations ("PR 1109.1"). The proposed rule would affect nine petroleum refineries, three small refineries, and four related operations, such as hydrogen production and sulfuric acid manufacturing, all located within Los Angeles County.

Under PR 1109.1, petroleum refineries and related operations will be required to install pollution control equipment to reduce their NOx emissions. Staff projects 284 pieces of equipment are potentially subject to PR 1109.1 and a subset of these units will require the installation or upgrade of control equipment including Selective Catalytic Reduction System (SCR) and/or Low-NOx Burner technology. PR 1109.1 has the potential for significant emission reductions, in the range of 7 – 9 tons per day.

This report has been commissioned by the South Coast AQMD to evaluate the impacts of PR 1109.1 on the prices and demand for refined products in the region. Central to this exercise is an evaluation of the pass-through of costs by refineries in the Los Angeles area. That is, when refinery costs rise, are refineries able to commensurately increase the prices of refined products? Or, does competition from refineries outside Los Angeles limit local refiners' ability to raise prices? To assess the impacts of PR 1109.1, I first discuss the economic concept of pass-through and how it relates to the specific details of the refined product markets in the South Coast AQMD region. I then provide two sources of evidence that speak to the appropriate pass-through rate for the compliance costs associated with PR 1109.1. Finally, I translate the pass-through estimates into impacts on prices and demand for refined fuels.

4 The Economics of Pass-through

Pass-through is defined as the amount by which a firm raises its price in response to changes in its underlying costs. Pass-through has fundamental implications for firm profitability as well as consumer welfare. Put simply, if a firm cannot pass-through cost increases, by raising the price at which it sells its goods to customers when its costs rise, the amount of profit it earns per unit sold declines. In these cases, the firm bears the burden of rising costs. But, if the firm can pass-through cost increases onto consumers by raising its prices, the firm can preserve its profit margin. In this case, consumers bear the burden of the cost increase in the form of higher prices.

Pass-through also plays a central role in policy analysis because a firm's costs arise from the taxes and regulations it faces, as well as the cost of inputs used for production. As regulations, fees, taxes or other imposed costs change, a firm may pass-through those costs onto consumer just as it might pass-through the costs of inputs to production. Understanding how much of these costs are passed-through to consumers speaks directly to whether consumers or producers bear the burden of the regulation, fee, tax or other cost change.

Before turning to the details of the refined product market in the South Coast AQMD region, I first discuss two broad ideas relevant to pass-through analysis and relevant to this report: (1) the factors that determine the degree of pass-through in a market, and (2) the distinction between different types of costs the implications for pass-through.

4.1 Pass-through is determined by competitive forces.

The ability of a firm to pass-through its costs is determined by competitive forces in the marketplace. If a firm does not face any pressure from competitors (or customers), it will happily pass-through any cost increase into higher prices at which it sells its goods. But, in practice, a firm faces competitive pressure from two sources that limit its ability to pass-through costs onto consumers.

The first source of competitive pressure comes, naturally, from other firms in the marketplace. If a firm (or set of firms) attempts to raise its price, other firms in the marketplace have incentive to undercut the higher price and increase their sales at the expense of the firm that raised price. This price competition is driven by the desire to maximize profits and is commonplace. In almost all industries, firms compete with and face competition from other firms in the marketplace all the time. Yet, some firms face more price competition than others. In particular, in industries or in markets where a large number of firms compete (or could easily compete if they so chose), the competitive pressure from is greater and further limits the firm from passing-through costs.[1] In contrast, if a firm faces few competitors or operates in a location that is costly for other firms to serve, it might be able to pass-through a higher proportion of a cost increase.

The second source of competitive pressure comes from the customers themselves. Customers decide whether to purchase a good and how much of a good to purchase based on the price they have to pay. For some goods, customers might have relatively little desire to curtail their consumption, even as prices rise. This might be the case for necessities, goods that have few substitutes, goods

[1]Although for purposes of exposition, I focus on the case where costs are rising, a similar intuition can apply to settings where costs fall. Where competition is high and a firm competes with many rivals, a firm might modestly lower its price if it's costs fall because it can steal customers from many of its competitors while increasing its profits per unit.

that consumers rely upon or goods for which customers have a very strong preference. But, for other goods, consumers might readily shift away from the good or curtail the amount they consume in response to higher prices. In economics, we use the demand elasticity as a measure of how responsive customer demand is to the price of a good. Mathematically, the demand elasticity is the percent change in demand caused by a one percent increase in the price of the good. The demand elasticity of the good can be thought of as the amount of "competitive pressure" that customers themselves exert upon firms. For inelastic goods, like necessities, customers continue to consume the good even if prices rise. All else equal, this lack of response by consumers enables a firm to pass-through a higher fraction of cost increases. But, if consumers readily reduce consumption in response to higher prices (i.e., demand is relatively elastic), a firm will not find it in its interest to raise prices as costs rise, since higher prices might drive away many of its customers.

It is important to note that the two sources of competitive pressure are unrelated. For some goods and in some markets, a firm might face little pressure from other firms, but might sell a good from which consumers readily switch away. And in other markets, a firm might sell a "necessity," but face price competition from many other firms in the marketplace. In both of these cases, the firm might have relatively little ability to pass-through input costs, taxes or regulatory costs.

4.2 Firms pass-through variable, not fixed costs

Economics distinguishes between two types of costs: variable and fixed costs. The former are costs that vary with the quantity produced by the firm. Typically, we think of most input costs, as well as taxes and fees that increase with production (like emissions fees), to be part of variable costs. Fixed costs, on the other hand, do not vary with the quantity produced by the firm and include most capital investments. Regardless of the amount a firm chooses to produce, the firm is responsible for the payments on any purchased capital or other fixed costs.

The distinction between variable and fixed costs is an important one for pass-through, because when the firm sets prices to maximize profits, those prices depend *on the variable costs the firm faces, not on the fixed costs*. To illustrate the intuition behind this insight, consider the example of a profit-maximizing gas station. When the gas station sets its price, that price balances two competing forces. As the gas station sets a higher price, it earns more on every gallon that it sells measured as the difference between the retail price and the firm's variable costs. But, as the firm sets a higher price, it also sells less gas, as the high price is unattractive to potential customers. Profit maximization balances these two considerations, raising price up until the point at which the loss of sales more than offsets any benefit to the firm from raising the profit margin on each unit sold.

Building on the example, suppose that the wholesale price of gasoline (i.e., the price at which the station purchases gasoline from a supplier) rises, increasing the gas station's variable costs. If the gas station does not change its prices, its profits will fall, since the wholesale price of gasoline has increased and it earn less profit on every gallon that it sells. But, if the gas station raises its price in response to the cost increase, it will recoup some of its lost profits, even if it sells slightly fewer gallons at the higher price. Because variable costs affect the incremental profit that a firm earns when it sells additional units of the good, a firm has the incentive to adjust its prices (and hence, amount it sells) in response to a variable cost change. Pass-through is a measure of this response, the amount by which prices change in response to a change in *variable costs*.[2]

In contrast, a firm's fixed costs do not affect the profit-maximizing prices it would set. Returning again the hypothetical example of a gasoline station above, suppose that the gas station faces a rent increase, rather than an increase in the wholesale price of gasoline. From the gas station's perspective, rent is a fixed cost. The station has to pay the rent to operate in any capacity, but the rent is a fixed amount that doesn't change if the firm sells more (or fewer) gallons of gasoline, unless the firm chooses to cease operations completely. While the rent increase does lower the firm's total profits, it does not affect the amount a firm earns for each incremental gallon that it sells (i.e., the difference between the retail price the station sets and the wholesale price the station pays to a supplier.) Consequently, the firm has no incentive to adjust its prices in response to the rent increase – if the firm was setting the profit-maximizing price before the rent increase, it would want to set the same price afterwards, because the underlying amount that it earns when it sells each gallon has not changed. Thus, although the fixed costs affect firm profits, fixed costs do not affect the profit maximizing prices that a firm would choose to set, and hence, are not passed-through to retail prices as are variable costs.

Many factors change a firm's variable costs. Naturally, a firm's input costs are an important consideration – in the setting of refined fuels, if the cost of crude oil rises, the cost to produce each unit of refined products rises commensurately. Regulatory policy can also affect a firm's variable costs. If, for example, the government levies per-unit taxes on a firm or charges emissions fees that depend on the amount that the firm produces, the taxes or fees change the amount of profit that the firm earns for each unit that it sells and can be thought of analogously to a change in input costs. Or, alternatively, if government regulation requires firms to add additional equipment or change their operations in a way that increases the cost to produce each unit of output, the firm will pass-through these costs in the same way it might pass-through the costs of rising input prices.

5 Features of the Refined Product Market in the South Coast AQMD region

I now describe the salient features of the refined product market in the South Coast AQMD region focusing on those particularly relevant to the pass-through analysis for PR 1109.1.

As a starting point, consider the demand for refined products and the extent to which consumer might influence the rate of pass-through. Refined petroleum products (such as gasoline, diesel fuel, kerosene and other petroleum products) tend to be relative inelastic goods with respect to price. For most uses, there are relatively few substitutes and it is difficult to substantially reduce consumption. As an example, consider gasoline, the vast majority of which is used for light-duty-transportation. Although drivers have options available to reduce gasoline consumption (e.g., in the short-run, individuals can carpool, take alternative forms of transportation or reduce

[2]Economists further distinguish *marginal* costs from variable costs, where a firm's marginal cost is the incremental cost of the last unit of the good produced. Although, technically, pass-through measures the degree to which a firm adjusts prices in response to marginal costs, in this setting, regulatory costs shift both marginal and inframarginal variable costs.

discretionary trips; in the longer-run, individuals shift towards higher mileage vehicles), a driver's gasoline consumption is largely driven by factors that are hard or costly to change, like where they live, what car they drive, and where they work. A long empirical literature in economics estimates the demand elasticity for gasoline and finds strong and consistent evidence with this intuition. Levin et al. (2017) and Li et al. (2014), to cite two recent examples, both estimate demand of gasoline to be inelastic, with elasticity estimates of -0.36 and -0.27, respectively. Translating the demand elasticities into a specific example, the estimates imply that a 10 percent increase in gasoline prices lowers overall demand for gasoline by a scant 3 percent.

Turning to the competitive pressure from the supply-side, refined products in Southern California come from several sources. The majority of refined products are produced locally. Although PR 1109.1 is expected to impact 16 facilities, this report focuses on the subset of the facilities that product the majority of gasoline and diesel in the Los Angeles area. This subset includes the Los Angeles area refineries of Chevron El Segundo, PBF Energy Torrance, Marathon Petroleum Carson, Marathon Petroleum Wilmington, Phillips 66 Carson, Phillips 66 Wilmington, and Valero Wilmington.[3] Collectively, these refineries have the capacity to process roughly one million barrels of oil per day and represent the vast majority of the refining capacity in the South Coast AQMD region.

Table 1 lists the refineries in Los Angeles, their distillation capacities and whether they produce gasoline or diesel fuel for California markets. For completeness, the table also lists two specialized small refineries in the Los Angeles area that produce asphalt that are also expected to be impacted by PR 1109.1. Figure 1a maps the location of the seven refineries in the Los Angeles metro area, along with the location of the ports of Long Beach and Los Angeles that can offload deliveries of refined petroleum products.

Table 1: Los Angeles Petroleum Refineries

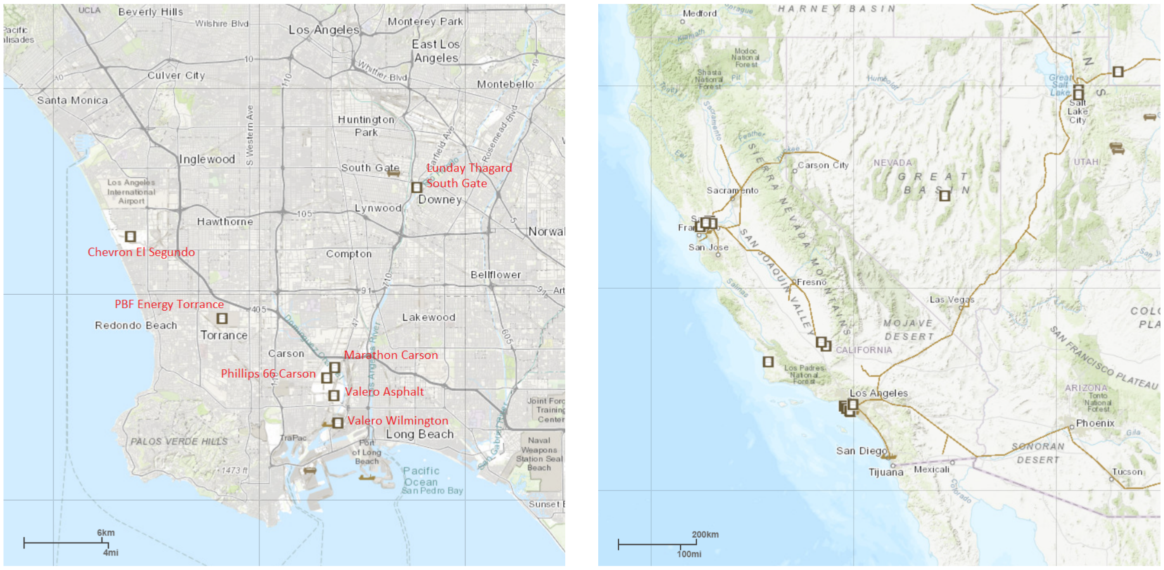
Refinery	Distillation Capacity in 2020 (bbls/day)	CARB gasoline	CARB diesel
Marathon, Carson/Wilmington	363,000	Yes	Yes
Chevron, El Segundo	269,000	Yes	Yes
PBF Energy, Torrance	160,000	Yes	Yes
Phillips 66, Carson/Wilmington	139,000	Yes	Yes
Valero, Wilmington	85,000	Yes	Yes
Lunday Thagard, South Gate	9,500	No	No
Valero, Wilmington (Asphalt)	8,500	No	No

CARB refers to the California Air Resources Board. Source: California Energy Commission, Energy Almanac. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/californias-oil-refineries

[3]In the subsequent tables, figures and discussion, the adjoining Marathon Petroleum refineries in Carson and Wilmington are aggregated together, consistent with refinery reporting by the California Energy Commission. Similarly, the linked Phillips 66 refineries in Carson and Wilmington are also aggregated.

Figure 1: Refining, Product Pipelines and Petroleum Ports

(a) Los Angeles Metro Area (b) California and Neighboring States



Source: Energy Information Administration, U.S. Energy Mapping System, https://www.eia.gov/state/maps.php. Refinery names added. Product pipeline maps are not publicly available at the geographic resolution of panel (a).

Supplementing local production of refined fuels, firms from outside Southern California ship refined product to the ports of Los Angeles and Long Beach. Barge shipments transport product from Northern California and tanker shipments move refined product to Southern California from other parts of the U.S. and the world, albeit with a several week delay.[4] But, relative to U.S. markets east of the Rocky Mountains that are relatively well-connected to Gulf Coast refineries by low-cost refined product pipelines, California (and the West Coast) is more isolated – no pipelines exist that deliver refined product to California.

California is further isolated by the fuel content requirements that dictate the chemical composition and properties of transportation fuels. California's fuel content regulations are more stringent than those required by the federal government.[5] As a result, fuel meeting California's requirements is more costly to produce and, hence, relatively few refineries outside of California regularly produce reformulated blendstock ("RBOB") that meets the more stringent California reformulated gasoline ("RFG") requirements. These unique features of the California market for refined fuels are widely recognized by industry participants, academics and policymakers.[6]

As a result of both the transportation constraints and the special requirements of California's transportation fuels, refined product shipments from outside the region are typically modest in volume. Relative to the local refining capacity in Los Angeles, that can process over one million barrels of oil per day, gasoline and distillate imports (including blendstock) from abroad into the

[4] Rail shipments of refined products are relatively low, although rail does deliver significant amounts of ethanol from the midwest to wholesale terminals in California for terminal blending into RBOB.

[5] California's reformulated gasoline Phase 3 standards (see Title 13, California Code of Regulations, sections 2250-2273.5) place more stringent limits on vapor pressure and require fuel meets other specifications supplementary to the federal reformulated gasoline requirements.(see Title 40, Code of Federal Regulations, section 1090.220)

[6] See, e.g., Factors Affecting Petroleum Markets at https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market

ports of Los Angeles, Long Beach and El Segundo averaged 21 thousand and 7 thousand barrels per day, respectively.[7] Although data on barge and tanker shipments from other parts of the U.S. are not available at the same level of geography, shipments to Los Angeles from other parts of the U.S. are similarly modest. Gasoline shipments from Northern to Southern California averaged, roughly 30 thousand barrels per day between 2015 - 2019.[8] Shipments from outside of the West Coast are smaller still. Aggregate gasoline and diesel shipments by barge or tanker from the Gulf Coast to the West Coast (PADD 5) collectively averaged approximately 6 thousand barrels per day over 2001 - 2020.[9]

Despite typically modest shipments into Los Angeles, competition from refineries outside the region play two important roles. First, refineries from outside the region compete with Los Angeles refineries to produce RBOB serve other the broader region. As mapped in Figure 1b, pipelines connect Los Angeles to San Diego, Phoenix and Las Vegas. Refined product delivered to Phoenix competes with refined product delivered on a west-bound pipeline from Texas, connecting through Tucson. And, similarly, refined product delivered to Las Vegas competes with product delivered by pipeline from Salt Lake City and other Rocky Mountain refineries. Second, most of Southern California's demand for refined products is served by the refineries in the Los Angeles area. But, when the prices of refined products rise in Los Angeles relative to other markets, refineries from outside the region increase shipments into the region, limiting the amount by which prices can rise.

6 Empirical Evidence on the Pass-through

This report assesses the potential impact of the PR 1109.1 under full implementaiton on prices and demand for refined products. Central to this exercise is specifying the appropriate pass-through rate for a change in variable costs arising from the costs of complying with the proposed rule. Yet, since the proposed rule has yet to be implemented, I use two separate approaches to benchmark the appropriate rate of pass-through. First, I compare the characteristics of the refined product market in California to the settings of previous studies that have estimated pass-through rates for refined products and examine the response of imports and competitive pressure from outside the region in response to supply shortfalls. Second, I directly estimate the pass-through for comparable costs arising from the RECLAIM program. As I discuss below, both of these approaches point towards a moderate pass-through rate, on the order of roughly 30%.

6.1 Benchmarking relative to previous studies suggests refineries can partially pass-through costs.

A first approach to determining the relevant pass-through rate for the compliance costs associated with PR 1109.1 relates the characteristics of the refined product market in the South Coast AQMD region to settings examined in previous work. Although previous studies don't focus specifically on refined products in the South Coast AQMD region, a comparison of the characteristics of the refined product market in the South Coast AQMD region to the settings used in previous studies provides one way to evaluate the relevant pass-through rate for PR 1109.1.

[7] Company Level Imports, Energy Information Administration, 2001 - 2020, summarized by author.

[8] Petroleum Watch, California Energy Commission, March 2021. https://www.energy.ca.gov/sites/default/files/2021-03/2021-03\%20Petroleum\%20Watch.pdf

[9] Movements by Tanker and Barge between PAD Districts, Energy Information Administration, 2001 - 2020, summarized by author.

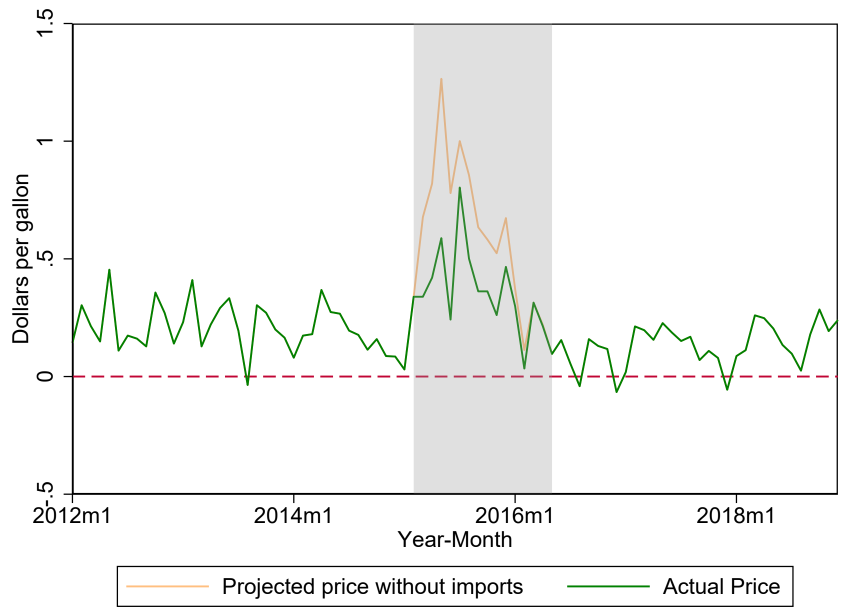
An important distinction highlighted in previous studies is that the ability of firms to pass-through cost, tax or regulatory changes depends on whether costs change for all (or virtually all) of the refiners selling into a market, or whether costs change for only a subset of refiners that supply a market. In the case of the former, changes to variable costs that affect all the firms serving a market are almost fully passed-through to consumers (see e.g., Marion and Muehlegger (2011)). This category of cost changes includes rising or falling world crude oil prices and state and federal taxes that are levied on all transportation fuel sold in an area, regardless of where the refined products were made. In both cases, all firms face higher costs, yet the demand for refined products is relatively inelastic and relatively few substitutes exist. Hence, the pass-through rate for a change in costs that affects all of the firms is unlikely to be tempered by consumers (due to relatively inelastic demand) nor by competition from other firms (as all firms are affected by world crude prices or fuel taxes). In such cases, firms pass-through the vast majority (if not all) of cost or tax changes onto consumers.

In contrast, if costs change for a subset of refiners serving a market, Muehlegger and Sweeney (2017) finds evidence of much lower pass-through rates. Moreover, as the number of firms affected by the cost change declines, so does the ability of the firm to pass-through cost changes. A firm has virtually no ability to pass-through cost changes that affect themselves alone, while pass-through for costs that affect the subset of firms that serve a market varies between 20 and 40 percent depending on the size of the market and the ability of firms outside the region to ship product into the market. Again, the intuition behind this result is relatively straightforward. Although the demand is still inelastic for the good, if costs only change for a few firms in the market, those firms still have to compete with the other firms for whom costs have not changed. The importance of the former group relative to the latter group dictates whether pass-through rates are very low or pass-through rates are closer to the full pass-through benchmark for world crude oil price changes or state fuel taxes.

Applying these ideas to the market for refined products in Southern California, several implications can be drawn. As discussed above, most of the refined product produced in Southern California is refined locally. Collectively, the five refineries in Los Angeles that produce refined product have the capacity to process roughly one million barrels of oil per day, the grand majority of which is processed into high margin products like gasoline and distillate. In comparison, other sources of supply (e.g., imports into the ports of Long Beach or Los Angeles, or shipments from other U.S. refineries) are a smaller fraction of the overall market. Yet, even these sources, small though they are, may provide competitive pressure on the refineries in Southern California, suggesting that partial pass-through, similar to the estimates for regional cost changes identified in Muehlegger and Sweeney (2017), is plausible.

As evidence of the competitive pressure created by the refineries outside the Los Angeles area, I examine the response of firms outside of Los Angeles to the fire at the ExxonMobil Torrance refinery (now owned by PBF Energy) in February 2015. The explosion and fire disabled the refinery's fluid catalytic cracking unit and required extensive, unexpected repairs to the refinery, lasting until May 2016. The sixteen-month refinery outage caused a substantial shortfall of almost one-sixth of the refinery capacity in Southern California and had a dramatic impact on market for gasoline. To be clear, the unexpected nature of the Torrance refinery fire partially contributed to the impact. Faced with a planned refinery maintenance or other expected change in production (such as a change that might be induced by PR 1109.1), refiners both inside and outside of Los Angeles would adjust production and inventories in advance and, in so doing, would smooth the impacts. Regardless, the Torrance refinery fire provides an excellent example of how refineries outside of Los Angeles adjust to serve the market in the South Coast AQMD region.

Figure 2: LA RBOB vs. Gulf Coast Gasoline Spot Differential, 2012 - 2018

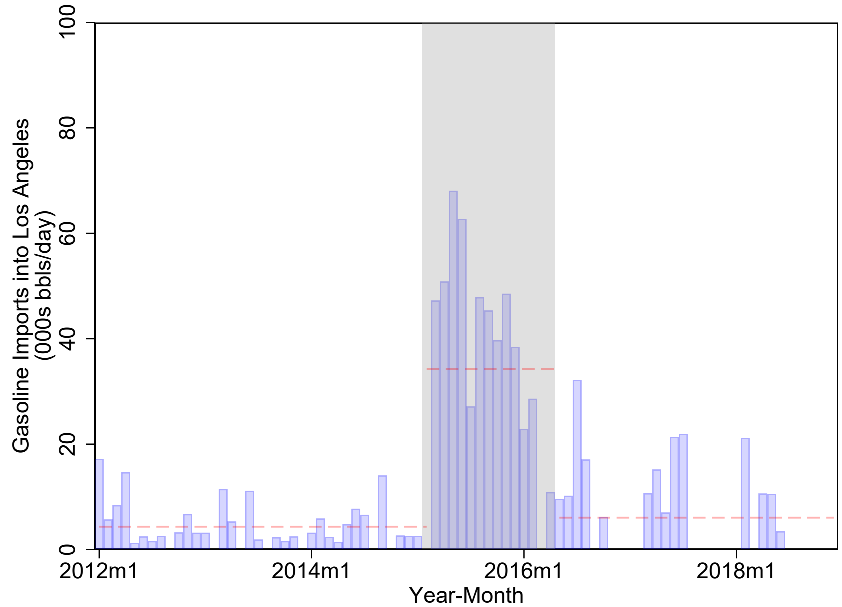


Notes: Grey region corresponds to the window during which the Torrance refinery was shutdown following the Feb. 2015 fire.
Source: EIA Spot Prices for Crude Oil and Petroleum Products, http://www.eia.gov/dnav/pet/pet_pri_spt_s1_m.htm,

Figure 2 plots (in green) the average price differential between the spot price for RBOB sold in Los Angeles and the spot price for conventional gasoline sold in the Gulf Coast. The window during which the Torrance refinery was under repairs is highlighted in grey. As the green line illustrates, the spot price in Los Angeles is regularly above the spot price for conventional in the Gulf Coast – if the spot prices were exactly equal, they would track the dotted red line plotted at zero on the y-axis. During the three years preceding the outage, the spot price for RBOB in Los Angeles was 20 cents per gallon higher than the spot price for conventional gasoline in the Gulf Coast. This premium reflects the more stringent environmental requirements required to meet RBOB specifications and the higher cost of refining in California relative to the Gulf Coast. During the outage window, this premium increases - averaging roughly 35 cents per gallon for the sixteen-months prior to the restart of the Torrance refinery in May 2016. After the refinery returned to operation, the RBOB spot premium declined, averaging 13 cents per gallon from June 2016 - December 2018.

On the one hand, the fifteen cent increase in the spot prices differential during the outage reflects the scarcity of gasoline supply in the West Coast and the relatively few numbers of refineries that produce gasoline that meets RBOB specifications. Yet, the outage led to a supply-side response from refineries outside of the region as well. Figure 3 plots total international deliveries of finished gasoline and blendstocks to either the port of Los Angeles or the port of Long Beach, over a similar time frame. As the figure illustrates, the shortage caused by the unexpected outage of the Torrance

Figure 3: Gasoline Imports into Los Angeles, 2012 - 2018



Notes: Grey region corresponds to the window during which the Torrance refinery was shutdown following the Feb. 2015 fire.
Source: EIA Company level imports, https://www.eia.gov/petroleum/imports/companylevel/

refinery (and the rising price premium of the RBOB spot price) stimulated production from outside the region. During the window of the Torrance refinery outage, foreign refineries began to produce gasoline meeting RBOB requirements.[10] Prior to the outage, international gasoline imports into the ports of Los Angeles and Long Beach averaged roughly seven thousand barrels per day (plotted as the left-most dotted line in Figure 3). But, shortly after the Torrance refinery fire, and contemporaneous with the increase in RBOB spot prices, international imports increased more than five-fold, replacing a substantial fraction of the lost gasoline production from the Torrance refinery.[11] Although we only observe what actually happened to spot prices for RBOB in Los Angeles, the yellow line in Figure 2 projects what might have happened if imports had not increased and the inelastic demand for gasoline had driven up the price, based on estimates of the gasoline price elasticity from Levin et al. (2017).[12] Absent the imports, customers would have had to curtail demand in response to the refinery outage. The yellow line represents how much prices would have had to increase, based on a demand elasticity of -0.36, to meet the refined product

[10] In principle, other domestic refineries might also have produced and supplied RBOB to Los Angeles, but publicly available data only tracks domestic shipments between PADDs and does not delineate shipments by destination to the same degree as the import data.

[11] Although figure 3 does not delineate between gasoline imports meeting and not meeting RBOB requirements, the data from the EIA does identify three broad classes of gasoline imports: (1) conventional gasoline or blendstock, (2) reformulated gasoline or blendstock and (3) gasoline blending components that are not designated as either meeting conventional gasoline or reformulated gasoline specifications. Roughly one-quarter of the imports were classified as each of the first two categories, whereas half of the imports during the outage window were classified simply as blending components.

[12] Levin et al. (2017) estimates gasoline demand elasticity based on daily price and purchase data for 243 U.S. cities. By comparing how purchases change as prices rise and fall, the paper estimates price elasticities of demand for gasoline between -0.27 and -0.36, depending on the specification.

shortage purely through a reduction in customer demand. The difference between what actually happened (the green line) and the projection of what might have happened absent imports (the yellow line) highlights the important role that imports (and foreign refineries) play in moderating spot prices in the California market.

6.2 Direct estimates for comparable policies are consistent with moderate rates of pass-through.

The preceding section suggests that moderate rates of pass-through (comparable to the 20 - 40 percent pass-through rates found in previous studies for changes in costs affecting a group of refineries that typically serve a local market) might be appropriate given the role that international refineries play as potential suppliers to the market for refined fuels in the South Coast AQMD region. Although international refineries do not typically ship substantial volumes of refined product to Los Angeles, they do form a set of competitors that can and do serve the market and act to temper price increases, such as those caused by the Torrance refinery fire in 2015.

To support this assessment, I directly estimate the pass-through rate for a policy comparable in scope to PR 1109.1, the RECLAIM program. RECLAIM is a local emissions trading program administered by South Coast AQMD that required firms to obtain and use tradeable emissions credits when emitting criteria pollutants, namely NOx and SOx. Although different in many ways than PR 1109.1, RECLAIM provides a suitable comparison because of the local scope of the program. Like PR 1109.1, RECLAIM applies to refineries only under the jurisdiction of the South Coast AQMD, raising costs for those firms relative to competitors from outside the region.

Policymakers often use tradeable credits (or permits) to reduce pollution from industrial facilities in a cost-effective manner. A credit trading program like RECLAIM has two key features. First, the number of credits creates a hard cap on the total amount of pollution that can be emitted. This provides a way for a jurisdiction to tighten the cap over time, gradually reducing pollution from industrial facilities. Second, the credits are tradeable, such that firms can buy or sell pollution rights amongst themselves in response to their needs. Tradability allows firms that cannot easily reduce pollution to purchase credits from firms that can reduce pollution at low cost or from facilities that shutdown. This ensures that pollution can be reduced in a cost-effective manner.

The price of the tradeable credits is determined by the interaction of supply and demand. If the number of credits is high relative to emissions, the equilibrium price will be low, as many potentially sellers may be willing to offer credits to potential buyers. But, if demand for emission credits rises or firms anticipate that supply will be more binding in the future, the equilibrium price of credits will rise.

Importantly, as the price of credits rises and falls, the variable costs of the firms rise and fall commensurately, since firms emitting pollution could choose to sell credits at the market price, rather than pollute. In economics, this is referred to as an “opportunity cost.” There are examples of opportunity costs in economics from education (in which students pay the “opportunity cost” of not working while in school) to lost time associated with taking a slower method of transportation. In this setting, the “opportunity cost” reflects the amount of money the firm could have earned if it had chosen to sell the credit rather than use the credit to emit pollution. This cost doesn’t depend on the actual price a firm paid for the credit – even if credits were purchased earlier at lower prices (or received for free), the market price of credits reflects the effective cost of the firm faces when it chooses to use a credit rather than sell it. The use of the market price as reflective of the oppotunity costs faced by a firm using pollution credits has been used in other papers to understand pass-through, notably Fabra and Reguant (2014) and Hintermann (2016), which examine how the price of tradable credits impact the cost of electricity generators and wholesale electricity prices.

To estimate the pass-through of RECLAIM credit prices, I use regression analysis to examine the degree to which the retail price of gasoline in Los Angeles changes in response to changes in emissions credit costs, measured on a comparable per-gallon basis. Regression analysis is an analytical technique that estimates the relationship between a set of explanatory variables and an outcome of interest. It provides a means to isolate the quantitative relationship between particular factors and the outcome, *holding the other explanatory variables fixed.* It is commonly used by businesses, policy-makers, governments, analysts and social scientists to understand quantitative relationships in many settings.

Here, regression analysis provides a means to estimate the pass-through rate of the cost of credits onto gasoline prices in the Los Angeles area, distinct from other changes that might affect the overall demand or supply of fuels in California.[13] To do so, the regression explains the per-gallon tax-inclusive retail price of gasoline in Los Angeles using two explanatory variables: changes in the per-gallon tax-inclusive retail price of gasoline in San Francisco and changes in the per-gallon average price of RECLAIM credits necessary to produce refined products.[14] The regression model estimates, on average, how much gasoline prices in Los Angeles change in months when the gasoline price in San Francisco changes or the opportunity cost of pollution (as measured by average credit price) changes.

I include the former explanatory variable to control for changes that affect the overall market for fuels in California. These include state-wide legislative or regulatory changes, like the Low Carbon Fuel Standard or changes to state fuel excise taxes, as well as shocks that impact fuel prices throughout California, like unexpected refinery outages. As presented in the Appendix, the regression model estimates a coefficient of roughly one for gasoline prices in San Francisco, suggesting that, on average, the retail gasoline prices in Los Angeles and San Francisco tend to move in unison. For every cent per gallon increase in retail prices in San Francisco, the retail price in Los Angeles also rises by roughly one cent per gallon as well. To be clear, this doesn't imply that there aren't other factors that might only affect northern or southern California. Other local regulatory changes, taxes, or fees might cause prices in the two locations to diverge. But, the coefficient does suggest that prices in northern and southern California do tend to move in unison, on average.

I include the latter variable to capture the changes in the cost to produce gasoline (and other products) at refineries in South Coast AQMD. As credit prices rise, the effective cost to produce gasoline at refineries in South Coast AQMD rises, relative to refineries outside the region. Likewise, if credit prices fall, the cost to produce gasoline also falls. If firms are able to pass-through credit costs into retail prices, the price of gasoline in Los Angeles should move in a similar direction as credit prices (controlling for changes in the overall fuel market in California). How much the price of gasoline changes as permit prices change provides an estimate of the pass-through rate.

[13]Although the scope of this report extends to refined products other than just gasoline, publicly-available data limitations preclude a similar analysis for other refined products.

[14]Further details of the data, regression model and results are provided in Technical Appendix A.

In contrast to the relatively tight relationship between the price of gasoline is Los Angeles and San Francisco, the regression model estimates a coefficient of roughly 0.30 for changes in the average RECLAIM NOx credit prices. Put in layman's terms, for a one cent-per-gallon increase in the cost of NOx credits, prices for retail gasoline rise by roughly 0.3 cents per gallon. Taken in concert with the qualitative argument in the previous section, the quantitative evidence is consistent with the conclusion that refineries in the Los Angeles area have the ability to partially pass-through cost changes into both spot and retail prices. All else equal, the competitive pressure on Los Angeles refineries prevents the refiners from fully passing-through the cost change onto credit prices. Although firms can and do increase prices in response to local conditions and/or cost changes, the competitive pressure from refineries outside the region limit their ability to do so fully. Based on the qualitative and quantitative evidence, I conclude that a pass-through rate of roughly 30% is appropriate as a benchmark for PR 1109.1.

7 Impact of the PR 1109.1 on Prices and Demand

With the pass-through estimate from the preceding section, I turn to estimating the impact of PR 1109.1 on retail prices and demand for fuels. As discussed in section 4, the pass-through rate reflects the amount by which a change in the variable costs of production are incorporated into the retail price of a good. By multiplying the pass-through rate and the anticipated compliance costs of the proposed rule, I reach an estimate of the impact of the proposed rule on retail prices.

I use estimates of the variable (O&M) and capital costs associated with PR 1109.1 under full implementation, as provided by the South Coast AQMD. The annual variable costs and the anticipated capital costs for the major refineries in Los Angeles are provided in columns 2 and 3 of Table 2.[15] Annual variable compliance costs vary across refineries, from a high of $8.6 million to $2.8 million. Capital costs exhibit similar variation, from $1.46 billion to $232 million. Based on these total capital costs, column 4 reports the annualized capital costs, using a 25-year investment lifetime and a discount rate (9.08%) based on the average cost of capital for the five parent companies that own the major refineries in Los Angeles.[16] In columns 5 and 6, I scale the annual variable costs (column 2) and the annualized fixed costs (column 4) into cents per gallon (cpg), based on the distillation capacity of each refinery and a capacity factor equal to the mean capacity factor (87.3%) of refineries on the West Coast (PADD 5) over 2000 - 2019, both as reported by the Energy Information Administration.

As argued in section 4.2, any pass-through estimate should focus on changes to the variable costs of production. Although the annual anticipated increase in operational costs as a result of PR 1109.1 is on the order of several million dollars a year per facility, when measured on a per-gallon basis, the increase in operational costs amounts to a fraction of a penny per gallon. Across all five refineries, the per-gallon increase in O&M costs, are roughly 0.2 cents per gallon of refined product.[17] Multiplying the average increase in per-gallon variable costs as a result of PR 1109.1 by the estimated rate of pass-through from the previous section, I estimate the proposed rule would have negligible effects on the price of refined fuels in the South Coast AQMD region.

[15] Refinery names are omitted for purposes of anonymity.

[16] The discount rate of 9.08% was chosen to be reflective of the average cost of capital faced by Los Angeles refiners. South Coast AQMD Socioeconomic Impact Assessments typically use a 4% real interest rate when annualizing capital costs. The use of the lower discount rate would lower annualized costs.

[17] As a point of reference, a refinery that processes, on average, 100 thousand barrels of oil per day, can produce roughly 1.5 billion gallons of refined product over the course of a year.

Table 2: Estimated Costs of PR 1109.1

	Estimated Costs ($mil)			Estimated Costs (cpg)	
		Capital Costs			Capital Costs
Refinery	O&M	Total	Annualized	O&M	Annualized
Refinery A	8.6	1,469	136.5	0.18	2.80
Refinery B	6.0	415	38.6	0.17	1.07
Refinery C	3.7	521	48.4	0.20	2.60
Refinery D	3.4	484	45.0	0.30	3.95
Refinery E	2.8	232	21.6	0.14	1.07
Average - All Refineries				0.20	2.30

Notes: Estimated O&M costs and total capital costs based on South Coast AQMD staff estimates. Annualization of fixed costs based on a 25-year lifetime and a weighted average cost of capital of 9.08%. Per gallon costs are calculated based on 2019 refinery distillation capacity and an average refinery capacity factor of 87.3%.

The anticipated capital investments associated with full-implementation of PR 1109.1 are fixed costs and would not naturally be considered in a pass-through calculation. But, as an upper-bound on the potential impacts of PR 1109.1, I calculate the change in per-gallon costs inclusive of annualized capital costs. The average increase in costs, inclusive of annualized fixed costs, is 2.50 cents per gallon. Applying a pass-through rate of 30%, prices for refined products would rise by less than a cent per gallon. The modest price increases imply little potential impact on fuel consumption.[18]

8 Discussion of Additional Considerations

The analysis above considers the impacts of PR 1109.1 using evidence from the current market for refined products in the South Coast AQMD region. Yet, the investments required under the proposed rule would be made gradually over time, during which the market for refined products might change in meaningful ways. This section discusses two potential ways in which the settings used above might differ from the setting that would exist after the proposed rule goes into effect, with particular emphasis on how those changes might affect the conclusions above. But, to be clear, none of the differences described below substantively change the fundamental conclusions of the analysis above.

8.1 Anticipation by market participants would further moderate price effects.

The empirical analysis in section 6 examines two events, changes in RECLAIM credit prices and the response to the Torrance refinery fire, to understand the extent to which refineries in Los Angeles might be able to pass-through the impact of a cost change. Yet, these events differ from the PR 1109.1 in a meaningful way. The Torrance refinery fire was unexpected as are changes in the prices of emissions credits under the RECLAIM program. In contrast, the investments required under the PR 1109.1 will occur gradually and are likely to be well-anticipated by market participants.

[18] A large academic and policy literature finds consistent evidence that the demand for transportation fuels is relatively inelastic with respect to price. See, e.g., Levin et al. (2017), and Li et al. (2014) as two recent studies, which estimate gasoline price elasticities of -0.36 and -0.27, respectively.

If competitors can benefit from adjusting their production in response to the proposed rule, anticipating the market changes allow them to respond in a more fluid fashion. A firm that anticipates the changes to the market can increase production of RBOB (or other fuels) in advance, schedule deliveries and manage operations in the way that incorporates the upcoming changes in a flexible manner. All else equal, this would tend to further limit the ability of regulated refineries to pass-through cost changes associated with the 1109.1 program.

As a specific illustration of this point, it is instructive to consider the response of the market to the Torrance refinery fire in February 2015. Immediately after the refinery fire, prices rose substantially and inventories were drawn down. But, after several weeks, foreign refineries adjusted their production, began to produce products like RBOB, and began to deliver the product to ports in Los Angeles. This lag, between the event and the response by firm in the market, reflects the time required by firms to adjust in response to unexpected market conditions and is one of the reasons why unexpected events (like a refinery fire) might have a large impact on prices. Yet, if the outage has been scheduled and anticipated by the other firms in the industry, it's reasonable to expect that the other firms, would adjust production in advance, so at so provide a more seamless transition.

8.2 Electrification of the vehicle fleet would further limit impacts.

Finally, it is instructive to consider how the market for refined fuels might change more broadly over the next several decades. We are on the cusp of a potential transformative shift in the transportation sector, away from a century-long reliance on fossil fuels in transportation towards electrification of the vehicle fleet. Yet, we are still early on this path. Even in California, where electric vehicle adoption has outpaced adoption in other states, the fleet of vehicles still runs almost entirely on gasoline. In 2020, the share of electric vehicles as a fraction of all vehicles on the road was roughly 2.2% in California and 2.6% in the Los Angeles Metropolitan Statistical Area.[19] But, as battery costs fall, the expectation by policymakers and industry participants is that a larger and larger share of the vehicle fleet will shift towards vehicles with electric powertrains.

This shift will have two impacts on the conclusions of this report. First and foremost, the gradual shift away from refined petroleum products for transportation will lower demand, gradually relaxing production constraints and leading to lower prices for transportation fuels. All else equal, this would tend to reduce the prices for refined products in Southern California. But, second, electrification of the vehicle fleet would tend to make the demand for gasoline more elastic (i.e., responsive to prices). Currently, the vast majority of multi-car households are still completely reliant on gasoline, and thus, have relatively little ability to substitute away from gasoline in response to higher prices. But, in a future world in which two-car households have one electric vehicle and one gasoline powered vehicle, households can more easily reduce gasoline consumption by shifting miles towards the household's electric vehicle. This would tend to make the demand for gasoline more elastic and consequently, reduce the ability of firms to pass-through cost increases.

[19] Source: California Energy Commission, Zero Emission Vehicle and Infrastructure Statistics, https://www.energy.ca.gov/data-reports/energy-insights/zero-emission-vehicle-and-charger-statistics.

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Li, S., Linn, J., and Muehlegger, E. (2014). Gasoline taxes and consumer behavior. *American Economic Journal: Economic Policy*, 6(4):302–42.

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Appendix A Technical Appendix

The goal of the regression analysis is to examine the pass-through of RECLAIM credit prices onto the retail prices of gasoline in the South Coast AQMD region, controlling for other factors that affect overall gasoline prices in California (such as the Low Carbon Fuel Standard, changes in state gasoline taxes or refinery outages that affect prices throughout the state.) By necessity, this exercise involves some abstraction away from the complex details of the RECLAIM program. Here, the empirical exercise estimates how retail prices for gasoline in Los Angeles change as RECLAIM tradable credits ("RTCs") increase or decrease in value. If firms pass-through the RTC price into the price at which they sell gasoline, we would expect a positive relationship between the two price series.

A.1 Regression Data

The data for the regression analysis come from two publicly-available sources. I use price publicly-available data for Los Angeles and San Francisco from the Energy Information Administration, which reports the monthly average tax-inclusive retail price (reported in cents per gallon) in a select set of major cities. For RTC prices, I use publicly-reported data on transactions provided by South Coast AQMD. The RECLAIM transaction data provides information on the total price, quantity and expiration date of all credits included as part of each arms-length transaction. Based on conversations with South Coast AQMD officials, I calculate average monthly RTC prices for 2000 - present, focusing specifically on Infinite Year Block ("IYB") transactions.[20] For each transaction, I calculate the per-pound NOx price that would rationalize the total price of the transaction given the quantity and expiration dates of all credits included as part of the transaction, discounted by the average cost of capital of the five refiners in Los Angeles. In months with more than one transaction, I calculate the quantity-weighted average per-pound price weighing across all transactions in that month. I further translate the monthly average RTC price into a monthly average price-per-gallon by dividing the per-gallon prices by average NOx emissions per gallon of refined product for the five major refineries in the Los Angeles area over 2000-2019, as provided by the South Coast AQMD.

A.2 Specification

To calculate the pass-through of the RTC prices through to retail prices of Los Angeles, I first-difference the retail prices and average infinite-year block RTC prices and regress the first-differenced retail price in Los Angeles against the first-differenced retail price in San Francisco and the first-differenced average price in RTC prices.

$$\Delta P_t^{LA} = \alpha + \beta \Delta P_t^{SF} + \gamma \Delta P_t^{RTC} + \varepsilon_t \tag{1}$$

where ΔP_t^{LA} and ΔP_t^{SF} correspond to the first-differenced retail gasoline prices in Los Angeles and San Francisco, respectively, in cents per gallon. ΔP_t^{RTC} is the first-differenced average price of infinite-year block RTC transactions.

[20] As described above, since the RTC price reflects the "opportunity cost" of emitting pollution, the analysis uses transactions involving one of the refineries in Los Angeles, as well as transactions between non-refining firms.

A.3 Results

Table 3 presents the results from the regression model. The specification in column 1 regresses the change in the average monthly retail price in Los Angeles on the change in the average monthly retail price in San Francisco and the change in the average NOx permit price, as described above. The coefficient on the retail price in San Francisco indicates that, all else equal, the two retail price series move in unison. The coefficient on the change in the average NOx permit price is estimated at 0.28, consistent with a pass-through rate of roughly 30%.

Table 3: Regression Results

	(1)	(2)
Retail Price in SF	1.02***	1.01***
	(0.030)	(0.042)
Brent Crude Price		0.042
		(0.041)
NOX Permit Price	0.28	0.46
	(1.04)	(1.10)
Observations	219	219
R-Squared	0.92	0.92

Notes: Standard errors are in parentheses. *, **, and *** denote significance at 10%, 5% and 1% significance level.

In parentheses, I report the standard errors of the point estimates. The standard error of the coefficient of the NOx permit price is substantially higher than the standard error on the coefficient of the retail price in San Francisco. This reflects the fact that there is less variation in the NOx permit price, and consequently, the coefficient is estimated with less precision. The magnitude of the standard error, relative to the point estimate, implies less statistical confidence in the coefficient on permit prices. Yet, the point estimate is generally consistent with the pass-through rates estimated (with greater statistical precision) in similar settings.[21]

In column 2, I report the point estimates of a specification that includes the change in the Brent crude spot price, in addition to the other two variables described above. Notably, the coefficient on the Brent crude spot price is estimated to be quite close to zero – after controlling for the retail price in San Francisco, the addition of the Brent crude spot price does help to explain the retail price in Los Angeles. In column 2, the original coefficients are largely unchanged. The estimate of pass-through is modestly higher, at 45%, but given the amount by which the proposed rule is anticipated to increase variable costs, still implies effects on prices of less than a penny per gallon, even if annualized capital costs are included.

[21] See, e.g., Muehlegger and Sweeney (2017).

Appendix B Curriculum Vitae

Erich Muehlegger - CV June 2021

ERICH J. MUEHLEGGER

CONTACT INFORMATION

University of California – Davis
Economics Department
One Shields Avenue
Davis, CA 95616

Phone: (617) 335-6083
Email: emuehlegger@ucdavis.edu
http://www.erichmuehlegger.com

ACADEMIC APPOINTMENTS

2014-present DEPARTMENT OF ECONOMICS, UC – DAVIS
Associate Professor (2016-present), Assistant Professor (2014-2016)
Graduate Program Chair (2016-2020)
Institute for Transportation Studies, Faculty Affiliate (2015-present)
Transportation, Technology and Policy Graduate Group, Affiliate (2015-present)
Davis Energy Economics Program, Faculty Affiliate (2014-present)

2005-2014 HARVARD KENNEDY SCHOOL, HARVARD UNIVERSITY.
Assistant Professor (2005-2010)
Associate Professor, untenured (2010-2014)
Harvard Environmental Economics Program, Faculty Fellow (2005-2014)
Regulatory Policy Program, Faculty Chair (2006-2009)
Harvard University Center for the Environment, Faculty Associate (2007-2014)
Harvard Lab for Economic Applications and Policy, member (2009-2014)

Spring 2010 DEPARTMENT OF ECONOMICS, COLUMBIA UNIVERSITY
Visiting Scholar

PROFESSIONAL APPOINTMENTS

2010-present NATIONAL BUREAU OF ECONOMIC RESEARCH, EEE
Research Associate (2016 – present)
Faculty Research Fellow (2010 – 2016)

2015-present JOURNAL OF ENVIRONMENTAL ECONOMICS AND MANAGEMENT,
Member of the Editorial Board

2018-present NATIONAL TAX JOURNAL,
Member of the Editorial Advisory Board

Erich Muehlegger - CV June 2021

EDUCATION

Primary Fields: Energy, Environment, Public Finance, Industrial Organization

2000-2005 MIT, CAMBRIDGE, MA. Ph.D., Economics.

1993-1997 WILLIAMS COLLEGE, WILLIAMSTOWN, MA. B.A., Mathematics and Economics

REFERENCES

Robert Stavins
Harvard Kennedy School
Robert_Stavins@harvard.edu
617-495-1820

Severin Borenstein
Haas School of Business, UC – Berkeley
borenste@haas.berkeley.edu
510-642-3689

Michael Greenstone
Department of Economics,
University of Chicago
mgreenst@mit.edu
617-452-4127

Lawrence Goulder
Department of Economics,
Stanford University
goulder@stanford.edu
650-723-3706

RESEARCH PUBLICATIONS

1. "Pass-Through of Own and Rival Cost Shocks: Evidence from the U.S. Fracking Boom" (with Richard Sweeney), forthcoming, ***Review of Economics and Statistics***

2. "Air Pollution and Criminal Activity: Microgeographic Evidence from Chicago" (with Evan Herrnstadt, Anthony Heyes and Soodeh Saberian), forthcoming, ***American Economic Journal: Applied Economics***

3. "Who Bears the Economic Burdens of Environmental Regulations?" (with Don Fullerton) ***Review of Environmental Economics and Policy****, 13:1, p.62-82, Winter 2019.*

4. "Tax Compliance and Fiscal Externalities: Evidence from U.S. Diesel Taxation." (with Justin Marion). ***Journal of Public Economics,*** 160, p. 1-13, April 2018.

5. "Does Tax-Collection Invariance Hold? Evasion and the Pass-Through of State Diesel Taxes" (with Justin Marion, Joel Slemrod and Wojciech Kopczuk). ***American Economic Journal: Economic Policy,*** 8: 2, p. 251-286, May 2016.

6. "Consumer Learning and Hybrid Vehicle Adoption" (with Garth Heutel) ***Environmental and Resource Economics***, 62:1, p.125-161, September 2015.

7. "Tracking Employment Shocks using Mobile Phone Data" (with Yu-ru Lin, Jameson Toole, Daniel Shoag, Marta Gonzalez and David Lazer), ***Journal of Royal Society Interface***, 12:107, June 2015.

8. "Gasoline Taxes and Consumer Behavior" (with Shanjun Li and Joshua Linn) ***American Economic Journal: Economic Policy***, 6: 4, p. 302-342, November 2014

9. "Weather, Salience of Climate Change and Congressional Voting" (with Evan Herrnstadt), ***Journal of Environmental Economics and Management***, 68: 3, p.435-448, November 2014.

10. "Consumer Response to Cigarette Excise Tax Changes" (with Lesley Chiou), ***National Tax Journal***, 67: 3, p. 621-650, September 2014.

11. "Heuristic Strategies, Firm Behavior and Industry Information" (with Cynthia Lin) ***Journal of Economic Behavior and Organization***, 86: 1, p. 10-23, February 2013.

12. "Tax Incidence and Supply Conditions" (with Justin Marion), ***Journal of Public Economics***, 95, p. 1202-1212. October 2011.

13. "Giving Green to Get Green: Incentives and Consumer Adoption of Hybrid Vehicle Technology." (with Kelly Gallagher), ***Journal of Environmental Economics and Management***, 61, p. 1-15. January 2011.

14. "Do Americans Consume Too Little Natural Gas? An Empirical Test of Marginal Cost Pricing" (with Lucas Davis), ***Rand Journal of Economics***, 41, p. 791-810. Winter 2010.

15. "Edgeworth Cycles Revisited" (with Joseph Doyle and Krislert Samphantharak). ***Energy Economics***, 32, p. 651-660. May 2010.

16. "Crossing the Line: The Effect of Cross-Border Cigarette Sales on State Excise Tax Revenues" (with Lesley Chiou), *B**E Journal – Economic Analysis and Policy (Contributions)***, 8:1. December 2008.

17. "Measuring Illegal Activity and the Effects of Regulatory Innovation: Tax Evasion and the Dyeing of Untaxed Diesel" (with Justin Marion). ***Journal of Political Economy***,116:4, p. 633-666, August 2008.

PUBLICATIONS IN MATHEMATICS

18. "Infinite Ergodic Index Z^d Actions in Infinite Measure" (with B. Narasimhan, A. Raich, C. Silva, M.Touloumtzis, and W. Zhao). ***Colloquium Mathematicum***, vol. 82, No. 2 (1999), 167-190.

19. "Lightly Mixing on Dense Algebras" with (A. Raich, C. Silva and W. Zhao). ***Real Analysis Exchange***, Vol. 23, No. 1, (1998), 259-266.

BOOK CHAPTERS AND OTHER PUBLICATIONS

20. "Land Use Regulation and Commuting Patterns" (with Daniel Shoag) ***Procedia Engineering*** *107*, p. 488-493, 2015.

*21. "*Cell Phones and Motor Vehicle Fatalities" (with Daniel Shoag), ***Procedia Engineering*** *78*, p. 173-177, September 2014.

22. Commentary on Dealing with Expropriations: General Guidelines for Oil Contracts, "The Natural Resources Trap: Private Investment without Public Commitment" MIT Press, 2011.

RECENT WORKING PAPERS

"Air Pollution as a Cause of Violent Crime" (with Evan Herrnstadt, Anthony Heyes and Soodeh Saberian)

"Correcting Estimates of Electric Vehicle Emissions Abatement: Implications for Climate Policy" (with David Rapson) ***revisions requested Journal of the Association of Environmental and Resource Economists***

"Subsidizing Low and Middle-Income Adoption of Electric Vehicles: Quasi-Experimental Evidence from California" (with David Rapson) ***revisions requested Journal of Public Economics***

"Future paths of electric vehicle adoption in the United States: Predictable determinants, obstacles and opportunities" (with James Archsmith and David Rapson)

OLDER WORKING PAPERS

"Gasoline Price Spikes and Regional Gasoline Content Regulations: A Structural Approach."

"Market Effects of Regulatory Heterogeneity: A Study of Regional Gasoline Content."

"Endogenous Facility Reliability: Evidence from Oil Refinery Fires"

FELLOWSHIPS AND GRANTS

2019 Principal Investigator, *Institute for Transportation Studies, SB1 2019-2020 Research Grant* "Do electricity prices affect EV adoption?" (with David Rapson and James Bushnell) $61,159

2018 Principal Investigator, *Institute for Transportation Studies, SB1 2018-19 Research Grant* "How much pollution abatement do EV subsidies buy us?" (with David Rapson) $75,710

2017	Principal Investigator, *Institute for Transportation Studies, SB1 2017-18 Research Grant* “Estimating the Effects of the Enhanced Fleet Modernization Project - Plus Up" and the Elasticity of Demand for Electric Vehicles” (with David Rapson) $79,986
2017	Principal Investigator, *National Center for Sustainable Transportation and California Department of Transportation* “Understanding the distributional impacts of vehicle policy: Who buys new and used alternative vehicles?” (with David Rapson) $99,101
2017	Principal Investigator, *National Center for Sustainable Transportation and US Department of Transportation* “Seed Grant: EV Incentive Pass-through and Dealer Margins” (with David Rapson) $31,400
2017	Principal Investigator, *Institute for Transportation Studies – Public Transportation Account Project* “Environmental Justice and Barriers to Low-Income EV Adoption” (with David Rapson) $39,824
2015	Principal Investigator, *New England University Transportation Center Research Grant*, “The Local Effects of the American Recovery and Reinvestment Act on Economic Activity and Traffic Safety” (with Daniel Shoag) $85,565
2014	Principal Investigator, *New England University Transportation Center Research Grant*, “Land-Use Regulation and Commuting Patterns” (with Daniel Shoag) $84,791
2013	Taubman Center for State and Local Government Research Grant ($15,000)
2013	KSG Dean’s Research Fund ($5,000)
2012	Taubman Center for State and Local Government Research Grant ($15,000)
2012	Principal Investigator, *New England University Transportation Center Research Grant*, “Cell Phones and Vehicle Safety”, (with Daniel Shoag) $97,303
2011	Taubman Center for State and Local Government Research Grant ($15,000)
2011	Principal Investigator, *Energy Technology and Innovation Project*, “Cell Phones and Vehicle Safety.” $32,822
2010	Principal Investigator, *Energy Technology and Innovation Project*, “Gasoline Taxes and Consumer Behavior.” $59,243
2007	Principal Investigator, *Mossavar-Rahmani Center for Business and Government and Energy Technology Innovation Project*, “Incentives for Hybrid Vehicles.” $28,635

2006	KSG Dean's Research Fund $5,000
2002	Fellowship, MIT Center for Energy and Environmental Policy Research.
2000-2003	National Science Foundation Graduate Research Fellowship

TEACHING AWARDS AND EXPERIENCE

2017	Tom Mayer Distinguished Teaching Award, UC Davis
2013	Dean's Award for Teaching, Harvard Kennedy School
2012	Dean's Award for Teaching, Harvard Kennedy School
2008	Dean's Award for Teaching, Harvard Kennedy School
2007	Dean's Award for Teaching, Harvard Kennedy School
2006	Dean's Award for Teaching, Harvard Kennedy School

UC-Davis:

ECN221C:	Graduate Industrial Organization (2014-present)
ECN121B:	Strategy, Competition and Regulation (2014-present)
ECN145:	Transportation Economics (2015 - present)

Harvard Kennedy School:

Executive Education: Modules on Empirical Methods and Environmental Policy

BGP200:	Strategy, Competition and Regulation (2008-2013)
API105:	Markets and Market Failure with Cases (2008)
API201:	Quantitative Analysis and Empirical Methods (2005 - 2008, 2011-2013)

OTHER EXPERIENCE

2003-2005	Teaching Assistant, MIT Department of Economics
2001-2002	Research Assistant, Professor Paul Joskow.
1997-2011	CompassLexecon, Cambridge, MA Analyst (1997-1998), Senior Analyst (1998-2000), Consultant (2000-2005), Academic Affiliate (2005-2011)

ACADEMIC PRESENTATIONS (SINCE 2005)

2021	Michigan State, Boston University, NBER EPEE, AERE Annual Conference

2019	USC, UCSB, TE3 conference, Empirical Methods in Energy Economics summer meeting
2018	ETH Zurich, Connecticut, Occasional Environmental Economics Conference (UCSB), Environmental Taxation Workshop (Maryland)
2017	UCLA, LSU, UC Berkeley Energy Camp, NBER Hydrocarbon Infrastructure meeting, Empirical Methods in Energy Economics summer meeting, AERE annual conference
2016	AERE annual conference, UC Berkeley Energy Camp, Arizona
2015	UC Irvine, UC Davis, Michigan
2014	UC Davis, UC Berkeley
2013	University of Colorado, Harvard, University of Illinois – Urbana Champaign, ETH Zurich, University of Lugano.
2012	Yale, UC Santa Barbara, ASSA meetings, Cornell.
2011	ASSA meetings, Stanford, Northwestern, UC Davis, Maryland AREC, UC Berkeley Energy Camp
2010	Columbia, Duke, International Industrial Organization Conference.
2009	Yale, Columbia Business School, Harvard, Columbia.
2008	American Economics Association Meetings, Boston University, International Industrial Organization Conference, Harvard (2), MIT, Brandeis, NBER Summer Institute – Economics of Taxation, NBER Summer Institute – Environmental and Energy Economics.
2007	Federal Reserve, Tufts, International Industrial Organization Conference, UC Berkeley, Yale.
2006	Harvard, International Industrial Organization Conference, Yale SOM, Federal Trade Commission, UC Berkeley.
2005	Harvard, Cornell, USC, UC Irvine, Northeastern, Department of Justice, Federal Trade Commission.

OTHER INVITED PRESENTATIONS

Academic Panel Lead – Climate Lab Roundtable on Green Tax Credits, June 2021.

Commentor – GAO Methodology: Effects of Mergers and Market Concentration on Wholesale Gasoline Prices. 2008, 2009

Lead Speaker, U.S. / Taiwan Dialogue on Hybrid Vehicles. Sponsored by the U.S. State Department. 2009.

PROFESSIONAL SERVICE

Referee for *American Economic Review, American Economic Review Insights, Quarterly Journal of Economics, Journal of Political Economy, Review of Economic Studies, Proceedings of the National Academy of Science, Review of Economics and Statistics, Journal of European Economics Association, AER Insights, AEJ: Microeconomics, AEJ: Economic Policy, AEJ: Applied Economics, Journal of Public Economics, RAND Journal of Economics, Journal of Environmental Economics and Management, Journal of Applied Econometrics, International Journal of Industrial Organization, Journal of the Association of Environmmental and Resource Economics, Journal of Industrial Organization, Journal of Industrial Economics, Review of Industrial Organization, Health Economics, National Tax Journal, Games and Economic Behavior, Scandinavian Journal of Economics, Southern Economic Journal, BE Journals in Economic Analysis and Policy, Energy Journal, Energy Economics, Journal of Policy Analysis and Management, Journal of Urban Economics, Environment and Resource Economics, Public Finance Review, Environmental Research Letters, International Tax and Public Finance, Energy Policy, Scandinavian Journal of Economics, Public Budgeting and Finance, Contemporary Economics and Policy, Science Advances*

American Economic Review Excellence in Refereeing Award, 2010.

Ad-hoc reviewer for *National Science Foundation, Canadian Social Science and Humanities Research Council, Alfred P. Sloan Foundation, NBER pre-doctoral fellowship committee.*

Conference committee member: *2016 AERE, 2017 AERE, 2018 AERE, 2018 NASMES, 2018 NTA Annual Meeting, 2018 EMEE, 2019 EMEE, 2019 AERE, 2019 NTA Annual Meeting, 2020 AERE, 2021 AERE*

Session Chair: *2006 IIOC, 2012 ASSA*, 2016 *AERE.*

Conference co-organizer: Making Social Science Transparent conference, UC Davis, April 2016

Discussant: 2011 NBER EEE, ASSA Meetings (2017, 2015(x3), 2014 (x2), 2013, 2011), 2010 NBER Winter IO, IIOC (2010, 2008, 2007, 2006), 2007 Harvard Conference on Oil and Populism. 2016 SOCCAM Meeting

COMMITTEE SERVICE

Department Service:
Graduate Program Chair (2016 – 2020)
Mental Health Committee (2020 – present)

Levine Family Seminar Series (2014)
Teaching Evaluation Committee (2014, 2015)
Industrial Organization Seminar Organizer (2015, 2016)
Environmental and Energy Economics Seminar co-organizer (2018)

Division Service:
Institute for Social Sciences Executive Committee (2015, 2016)
Graduate Studies Support Committee (2018-2020, member) (2020-2021, chair)

University Service:
Graduate Affairs Committee for Energy Graduate Group (2016 – present)
Department Representative to the Academic Senate (2017 - present)

Other Service:
Academic Affairs committee member, Energy Graduate Group (2017 - 2019)

Previous Committee Service:
HKS Faculty Research Seminar Coordinator (2011, 2012)

PhD Admissions Committee (2009 - 2013)
Junior Analytics Search Committee (2006 - 2008).
MPP Admissions Committee (2005).

Joseph Crump Fellowship Committee (2008 - 2012)
Harvard University Center for the Environment Fellowship Committee (2008)
Student Internship Fund Committee (2005, 2007)

ADVISING

Oral exam committee member:

2014-2015: Khaled Kheiravar, Jiwon Lee, Ariel Pihl, Irwin Rojas (ARE)
2015-2016: James Archsmith (chair), Yuan Chen (ARE)
2016-2017: Guozhen Li (TTP), Hanjiro Ambrose (TTP), Natalie Popovich (ARE), Tongxin Xu (TTP)
2017-2018: Kelsey Fortune, Jack Gregory (ARE)
2018-2019: Ethan Krohn, Nick Bowden (EGG), Armando Rangel (ARE), Xiaotong Su
2019-2020: Megan Song (ARE), Yijing Wang (ARE)
2020-2021: Shotaro Nakamura, Qian Wang (ARE), Sarah Smith (ARE), Sonia Wang (ARE)

PhD Dissertations - Kate Emans (2008, Amherst College)
Jonathan Borck (2008, Analysis Group)
Hunt Allcott (2009, NYU)
David Molin (2009, CompassLexecon)
Matthew Ranson (2012, Abt Associates)
Richard Sweeney (2015, Boston College)

Evan Herrnstadt (2015, HUCE post-doc)
Samuel Stolper (2016, Michigan SNRE)
James Archsmith (2017, Maryland AREC)
Natalie Popovich (2019 ARE, Berkeley National Labs)
Khaled Kheiravar (2019, California Air Resources Board)
Tongxin Xu (TTP, 2019, Xmotors)
Ethan Krohn (2020, U.S. Census Bureau)
Nick Bowden (EGG, 2020, Ameren Corporation)
Jack Gregory (ARE)
Kelsey Fortune
Xiaotong Su
Armando Rangel (ARE)
Reid Taylor
Kepler Illich
Jiyeon Cheon (ARE)
Qian Wang (ARE)
Pedro Orozco (ARE)

Master's Theses - Alemayehu Kuma Awas (2006, MPA-ID)
Jonathan Phillips (2007, MPP)
Issac Wohl (2007, MPP)
Erik Wurster (2007, MPP)
David Grasso (2009, MPP)
Bruce Haupt (2009, MPP)
Claudia Sanchez (2009, MPP)
Sierra Peterson (2009, MPP)
Daniel Vetter (2011, MBA/MPP)

Undergrad Theses - Michael Libert (2009, Economics)

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Subsequent Environmental Assessment for:

Proposed Rule 1109.1 - Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Industries, Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations, Proposed Amended Rule 1304 – Exemptions, Proposed Amended Rule 2005 – New Source Review for RECLAIM, and Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries

October 2021

State Clearinghouse No. 2014121018
South Coast AQMD No. 20210901KN

Executive Officer
Wayne Nastri

Deputy Executive Officer
Planning, Rule Development and Area Sources
Sarah Rees, Ph.D.

Assistant Deputy Executive Officer
Planning, Rule Development and Area Sources
Susan Nakamura

Assistant Deputy Executive Officer
Planning, Rule Development and Area Sources
Ian MacMillan

Authors:	Kevin Ni	Air Quality Specialist
	Ryan Bañuelos	Air Quality Specialist
	Alina Mullins	Air Quality Specialist
	Kendra Reif	Air Quality Specialist
	Tina Su	Air Quality Specialist
Technical Assistance:	Sarady Ka	Air Quality Specialist
	Zoya Banon, Ph.D.	Air Quality Specialist
	Mojtaba Moghani, Ph.D.	Air Quality Specialist
	Steve Tsumura	Air Quality Specialist
Reviewed By:	Barbara Radlein	Program Supervisor, CEQA
	Lijin Sun	Program Supervisor, CEQA
	Heather Farr	Program Supervisor
	Michael Krause	Planning and Rules Manager
	Barbara Baird	Chief Deputy Counsel
	Veera Tyagi	Principal Deputy District Counsel
	William Wong	Principal Deputy District Counsel

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GOVERNING BOARD

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Mayor Pro Tem, South Pasadena
Cities of Los Angeles County/Eastern Region

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Governor's Appointee

SHIELA KUEHL
Supervisor, Third District
County of Los Angeles

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Mayor Pro Tem, Highland
Cities of San Bernardino County

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Speaker of the Assembly Appointee

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Cities of Los Angeles County, Western Region

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Mayor Pro Tem, Yorba Linda
Cities of Orange County

JANICE RUTHERFORD
Supervisor, Second District
County of San Bernardino

EXECUTIVE OFFICER:
WAYNE NASTRI

PREFACE

This document constitutes the Final Subsequent Environmental Assessment (SEA) for Proposed Rule (PR) 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Industries, PR 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations, Proposed Amended Rule (PAR) 1304 – Exemptions, PAR 2005 – New Source Review for RECLAIM, and Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries.

The Draft SEA was circulated for a 46-day public review and comment period from September 3, 2021 to October 19, 2021. Five comment letters were received during the comment period and one comment letter was received after the close of the comment period. The comments and responses relative to the Draft SEA are included in Appendix F of this Final SEA.

In addition, subsequent to the release of the Draft SEA for public review and comment, minor modifications were made to the proposed project. PR 1109.1 was reorganized for clarity. PR 429.1 was updated with additional definitions, and applicability and certain provisions were re-worded for clarity. PAR 1304 was updated to clarify in subparagraph (f)(1)(E) that a mass balance calculation can be used to calculate the increase in PM emissions for the purpose of determining federal major NSR applicability, and other portions of the rule were updated for consistency. No changes were made to PAR 2005. The updates to the CEQA analysis include incorporating equipment replacement projects along with the associated change to other projects, and correcting GHG emissions in chapter 4 and Appendix C for ULNB replacement projects to match the values previously calculated in Appendix B CalEEMod modeling. To facilitate identification of the changes between the Draft SEA and the Final SEA, modifications to the document are included as underlined text and text removed from the document is indicated by ~~strikethrough text~~. To avoid confusion, minor formatting changes are not shown in underline or strikethrough mode.

Staff has reviewed the modifications to the proposed project, and concluded that none of the revisions constitute significant new information, because: 1) no new significant environmental impacts would result from the proposed project, 2) there is no substantial increase in the severity of an environmental impact, 3) no other feasible project alternative or mitigation measure was identified that would clearly lessen the environmental impacts of the project and was considerably different from others previously analyzed, and 4) the Draft SEA did not deprive the public from meaningful review and comment. In addition, revisions to the proposed project in response to verbal or written comments during the rule development process would not create new, unavoidable significant effects. As a result, these revisions to the Draft SEA merely clarify, amplify, or make insignificant modifications which do not require recirculation of the Draft SEA pursuant to CEQA Guidelines Sections 15073.5 and 15088.5. Therefore, the Draft SEA has been revised to include the aforementioned modifications such that it is now a Final SEA.

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CHAPTER 1

EXECUTIVE SUMMARY

1.0 INTRODUCTION

The California Legislature created the South Coast Air Quality Management District (South Coast AQMD) in 1977[1] as the agency responsible for developing and enforcing air pollution control rules and regulations in the South Coast Air Basin and portions of the Salton Sea Air Basin and Mojave Desert Air Basin. In 1977, amendments to the federal Clean Air Act (CAA) included requirements for submitting State Implementation Plans (SIPs) for nonattainment areas that fail to meet all federal ambient air quality standards [CAA Section 172], and similar requirements exist in state law [Health and Safety Code Section 40462]. The federal CAA was amended in 1990 to specify attainment dates and SIP requirements for ozone, carbon monoxide (CO), nitrogen dioxide (NO2), and particulate matter with an aerodynamic diameter of less than 10 microns (PM10). In 1997, the United States Environmental Protection Agency (U.S. EPA) promulgated ambient air quality standards for particulate matter with an aerodynamic diameter less than 2.5 microns (PM2.5). The U.S. EPA is required to periodically update the national ambient air quality standards (NAAQS).

In addition, the California Clean Air Act (CCAA), adopted in 1988, requires the South Coast AQMD to achieve and maintain state ambient air quality standards for ozone, CO, sulfur dioxide, and NO2 by the earliest practicable date [Health and Safety Code Section 40910]. The CCAA also requires a three-year plan review, and, if necessary, an update to the SIP. The CCAA requires air districts to achieve and maintain state standards by the earliest practicable date and for extreme non-attainment areas, to include all feasible measures pursuant to Health and Safety Code Sections 40913, 40914, and 40920.5. The term "feasible" is defined in the California Environmental Quality Act (CEQA) Guidelines[2] Section 15364, as a measure "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social, and technological factors."

By statute, the South Coast AQMD is required to adopt an air quality management plan (AQMP) demonstrating compliance with all federal and state ambient air quality standards for the areas under the jurisdiction of the South Coast AQMD[3]. Furthermore, the South Coast AQMD must adopt rules and regulations that carry out the AQMP[4]. The AQMP is a regional blueprint for how the South Coast AQMD will achieve air quality standards and healthful air, and the 2016 AQMP[5] contains multiple goals promoting reductions of criteria air pollutants, greenhouse gases (GHGs), and toxic air contaminants (TACs). In particular, the 2016 AQMP states that both oxides of nitrogen (NOx) and volatile organic compounds (VOC) emissions need to be addressed, with the emphasis that NOx emission reductions are more effective to reduce the formation of ozone and PM2.5. Ozone is a criteria pollutant shown to adversely affect human health and is formed when VOCs react with NOx in the atmosphere. NOx is a precursor to the formation of ozone and PM2.5, and NOx emission reductions are necessary to achieve the ozone standard attainment. NOx emission reductions also contribute to attainment of PM2.5 standards.

In October 1993, the South Coast AQMD Governing Board adopted Regulation XX – Regional Clean Air Incentives Market (RECLAIM) to reduce NOx and oxides of sulfur (SOx) emissions from high emitting facilities. The RECLAIM program was designed to take a market-based

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1 The Lewis-Presley Air Quality Management Act, 1976 Cal. Stats., Ch. 324 (codified at Health and Safety Code Section 40400-40540).
2 The CEQA Guidelines are codified at Title 14 California Code of Regulations Section 15000 *et seq.*
3 Health and Safety Code Section 40460(a).
4 Health and Safety Code Section 40440(a).
5 South Coast AQMD, Final 2016 Air Quality Management Plan, March 2017. https://www.aqmd.gov/home/air-quality/clean-air-plans/air-quality-mgt-plan/final-2016-aqmp

approach to achieve emission reductions, as an aggregate. The RECLAIM program was created to be equivalent to achieving emission reductions under a command-and-control approach, but by providing facilities with the flexibility to seek the most cost-effective solution to reduce their emissions. The market-based approach used in RECLAIM was based on using a supply-and-demand concept, where the cost to control emissions and reduce a facility's emissions would eventually become smaller than the diminishing supply of NOx RECLAIM trading credits (RTCs). However, analysis of the RECLAIM program over the long term has shown that the ability to achieve actual NOx emission reductions has diminished, due to a large amount of RTCs resulting from shutdowns being re-introduced into the market prior to amendments to Rule 2002 in October 2016 to address this issue.

The 2016 AQMP recognized that many of the RECLAIM program's original advantages were diminishing, and in Control Measure CMB-05 – Further NOx Reductions from RECLAIM Assessment, committed to achieving NOx emission reductions of five tons per day by 2025. Also, the South Coast AQMD Governing Board directed staff to implement an orderly sunset of the RECLAIM program to achieve the additional five tons per day. Thus, CMB-05 committed to a process of transitioning NOx RECLAIM facilities to a command-and-control regulatory structure and to ensure that the applicable equipment will meet Best Available Retrofit Control Technology (BARCT) level equivalency as soon as practicable.

In July 2017, the Governor approved California State Assembly Bill (AB) 617 which addresses community monitoring and non-vehicular air pollution (criteria pollutants and toxic air contaminants). AB 617 contains an expedited schedule for implementing BARCT at cap-and-trade facilities; industrial source RECLAIM facilities that are in the cap-and-trade program are subject to the requirements of AB 617. Under AB 617, air districts are required to develop by January 1, 2019, an expedited schedule for the implementation of BARCT no later than December 31, 2023, with the highest priority given to older, higher-polluting units that will need retrofit controls installed.

As a result of Control Measure CMB-05 from the 2016 AQMP and consistent with AB 617, South Coast AQMD staff has been directed by the Governing Board to begin the process of transitioning the current regulatory structure for NOx RECLAIM facility emissions to an equipment-based command-and-control regulatory structure per South Coast AQMD Regulation XI – Source Specific Standards. Thus, in the March 2017 Final Program Environmental Impact Report (EIR) for the 2016 AQMP, South Coast AQMD staff conducted a programmatic analysis of the RECLAIM equipment at each facility to determine if there are appropriate and up-to-date BARCT NOx limits within existing South Coast AQMD command-and-control rules for all RECLAIM equipment. This analysis concluded that command-and-control rules would need to be adopted and/or amended to reflect current BARCT and provide implementation timeframes for achieving BARCT. Consequently, South Coast AQMD staff determined that facilities should not exit the RECLAIM program unless their NOx emitting equipment is subject to an adopted future BARCT command-and-control rule.

As such, South Coast AQMD staff developed Proposed Rule (PR) 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations, to facilitate the transition of affected equipment operating at 16 petroleum refineries and related industries that are subject to the NOx RECLAIM program to a command-and-control regulatory structure and to implement Control Measure CMB-05. PR 1109.1 proposes to establish BARCT requirements to reduce NOx emissions while not increasing CO emissions from petroleum refineries and facilities with operations related to petroleum refineries which include asphalt plants, biofuel plants, hydrogen production plants, facilities that operate petroleum coke calciners, sulfuric acid plants, and sulfur recovery plants. The following combustion equipment categories will be applicable to PR 1109.1: 1) boilers; 2) gas turbines; 3) ground level flares; 4) fluidized catalytic cracking units (FCCUs); 5) petroleum coke calciners; 6) process heaters; 7) sulfur recover units/tail gas treating units (SRU/TGs); 8) steam methane reformer (SMR) heaters; 9) SMR heaters with gas turbine; 10) sulfuric acid furnaces; and 11) vapor incinerators.

The BARCT NOx concentration limits in PR 1109.1 are expected to be achieved primarily by installing new or modifying existing post-combustion air pollution control equipment such as selective catalytic reduction (SCR) technology or retrofitting existing combustion equipment with ultra-low NOx burners (ULNB). For FCCUs and petroleum coke calciners, wet gas scrubber technology utilizing a Low Temperature Oxidation Application (LoTOx™ with WGS), or dry gas scrubber technology utilizing an UltraCat™ Application (UltraCat™ with DGS) may be selected by facility operators in lieu of SCR technology to achieve the BARCT emission limits. Utilization of these various NOx emission control technologies is expected to create secondary adverse impacts which are analyzed in this CEQA document.

Although designed to reduce NOx emissions, installations of new or modifications of existing SCR technology to comply with the BARCT requirements in PR 1109.1 will cause concurrent increases in emissions of PM10 and SOx from the use of ammonia as a NOx reduction agent due to the presence of sulfur in refinery fuel gas. In addition, these increases of co-pollutant emissions may, in turn, require facility operators to reduce the sulfur content in refinery fuel gas in order to comply with existing Best Available Control Technology (BACT) requirements pursuant to New Source Review (NSR).

To address the potential emission increases of PM10 and SOx associated with installation of new or modified SCR technology to comply with the proposed BARCT emission limits in PR 1109.1, amendments to the New Source Review requirements in Rule 1304 – Exemptions and Rule 2005 – New Source Review for RECLAIM, are proposed that would provide a limited exemption to allow facilities implementing BARCT requirements pursuant to PR 1109.1 to focus on achieving NOx emission reductions without having to concurrently reduce the sulfur content in refinery fuel gas that would otherwise be required by BACT.

To address emissions that may occur during the start-up or shutdown of a combustion unit and/or its associated air pollution control equipment due to the lack of steady-state conditions during these events and the fact that these emissions may exceed the proposed BARCT emission limits in PR 1109.1, PR 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations, has been developed. Specifically, PR 429.1 proposes new requirements for startup, shutdown, and certain maintenance events, including an exemption from the NOx and CO emission limits in PR 1109.1 during these events. PR 429.1 also proposes notification and recordkeeping requirements for units that will be subject to PR 1109.1.

Finally, because the proposed adoption of PR 1109.1 will make existing Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries outdated and no longer necessary, Rule 1109 is proposed to be rescinded.

The December 2015 amendments to the NOx RECLAIM program projected a total of 14 tons per day of NOx emission reductions from reducing NOx RTC allocations from the refinery and non-refinery sectors. At the December 2015 public hearing, however, the South Coast AQMD Governing Board adopted a revised version of the NOx RECLAIM proposal with a reduced NOx RTC shave amount of 12 tons per day, weighted for BARCT, and a delayed implementation schedule. The analysis of the environmental impacts in the December 2015 Final PEA for NOx RECLAIM was based on what physical modifications would need to be made at the affected facilities in order to achieve the entire 14 tons per day of NOx emission reductions. The analysis also indicated that the NOx emission reductions would result in an environmental co-benefit by regionally reducing annual PM2.5 concentration regionwide by 0.7 micrograms per cubic meter ($\mu g/m^3$). However, a substantial portion of the NOx emission reductions were expected to be achieved via employing SCR technology and to a lesser extent UltraCat™ with DGS, which both require the use of ammonia. The analysis in the December 2015 Final PEA for NOx RECLAIM estimated that 1.63 tons per day of ammonia would be needed to reduce NOx emissions and a portion of the ammonia would remain unreacted and instead would be emitted as ammonia slip. In the atmosphere, emissions of ammonia slip chemically convert to PM2.5. The analysis in the December 2015 Final PEA for NOx RECLAIM estimated that a regionwide annual increase in PM2.5 concentration of 0.6 $\mu g/m^3$ regionwide would occur from the ammonia slip. Overall, to achieve 14 tons per day of NOx emission reductions, a corresponding regionwide annual decrease in PM2.5 concentration of 0.1 $\mu g/m^3$ was expected to occur.

The proposed project is estimated to reduce NOx emissions by approximately seven to eight tons per day, while not increasing CO emissions. The analysis in this SEA indicates that if a ~~maximum~~ <u>minimum</u> of ~~eight~~ <u>seven</u> tons per day of NOx emission reductions is achieved, a corresponding regionwide annual reduction in PM2.5 concentration of ~~0.4~~ <u>0.35</u> $\mu g/m^3$ would result. As with the December 2015 amendments to NOx RECLAIM, facilities affected by the currently proposed project are anticipated to make physical modifications by installing new or modifying existing air pollution control equipment in order to achieve the proposed BARCT NOx concentration limits of PR 1109.1, with the majority of the modifications relying on SCR technology which utilizes ammonia. The analysis in this SEA indicates that implementation of the proposed project is estimated cause ~~0.625~~ <u>0.647</u> tons per day of ammonia slip. Once in the atmosphere, emissions of ammonia slip from the proposed project are projected to chemically convert to a regionwide annual increase in PM2.5 concentration of ~~0.23~~ <u>0.24</u> $\mu g/m^3$ average. If the maximum eight tons per day of NOx emission reductions is achieved for the proposed project overall, a corresponding regionwide net decrease in annual PM2.5 concentration of ~~0.12~~ <u>0.11</u> $\mu g/m^3$ is also expected.

1.1 CALIFORNIA ENVIRONMENTAL QUALITY ACT

The California Environmental Quality Act (CEQA) requires that all potential adverse environmental impacts of proposed projects be evaluated and that methods to reduce or avoid identified significant adverse environmental impacts of these projects be implemented, if feasible. The purpose of the CEQA process is to inform the South Coast AQMD Governing Board, public agencies, and interested parties of potential adverse environmental impacts that could result from implementing the proposed project and to identify feasible mitigation measures or alternatives, when an impact is significant.

Public Resources Code Section 21080.5 allows public agencies with regulatory programs to prepare a plan or other written documents in lieu of a Negative Declaration or EIR once the Secretary of the Resources agency has certified the regulatory program. The South Coast AQMD's regulatory program was certified on March 1, 1989 [CEQA Guidelines Section 15251(l)]. In addition, the South Coast AQMD adopted Rule 110 – Rule Adoption Procedures to Assure

Protection and Enhancement of the Environment, which implements the South Coast AQMD's certified regulatory program. Under the certified regulatory program, the South Coast AQMD typically prepares an Environmental Assessment (EA) to evaluate the environmental impacts for rule projects proposed for adoption or amendment.

PRs 1109.1 and 429.1, Proposed Amended Rules (PARs) 1304 and 2005, and the proposed rescission of Rule 1109 are considered a "project" as defined by CEQA. By transitioning affected combustion equipment operated at NOx RECLAIM facilities specific to the petroleum refinery and related industries to a command-and-control regulatory structure, NOx RECLAIM facilities with equipment subject to PR 1109.1 will be required to meet the applicable NOx and CO emission limits. The decision to transition from NOx RECLAIM into a source-specific command-and-control regulatory structure was approved by the South Coast AQMD Governing Board as Control Measure CMB-05 in the 2016 AQMP, and the potential environmental impacts associated with the 2016 AQMP, including Control Measure CMB-05, were analyzed in the Final Program EIR certified in March 2017 (referred to herein as the March 2017 Final Program EIR for the 2016 AQMP)[6]. The environmental impacts from the transition to a command-and-control structure consist of the environmental impacts associated with implementing various emission reduction strategies, as described in the March 2017 Final Program EIR for the 2016 AQMP and this document.

The March 2017 Final Program EIR for the 2016 AQMP determined that the overall implementation of Control Measure CMB-05 has the potential to generate adverse environmental impacts in seven topic areas – air quality, energy, hazards and hazardous materials, hydrology and water quality, noise, solid and hazardous waste, and transportation. More specifically, the March 2017 Final Program EIR evaluated the impacts from installation and operation of additional control equipment and SCR or selective non-catalytic reduction (SNCR) equipment potentially resulting in construction emissions, increased electricity demand, hazards from additional ammonia transport and use, increase in water use and wastewater discharge, changes in noise volume, generation of solid waste from construction and disposal of old equipment, and catalysts replacements, as well as changes in traffic patterns and volume. For the entire 2016 AQMP, the analysis in the March 2017 Final Program EIR concluded that significant and unavoidable adverse environmental impacts were expected to occur after implementing mitigation measures for the following environmental topic areas: 1) aesthetics from increased glare and from the construction and operation of catenary lines and use of bonnet technology for ships; 2) construction-related air quality and GHGs; 3) energy (due to increased electricity demand); 4) hazards and hazardous materials due to (a) increased flammability of solvents; (b) storage, accidental release, and transportation of ammonia, (c) storage and transportation of liquefied natural gas (LNG); and (d) proximity to schools; 5) hydrology (water demand); 6) construction noise and vibration; 7) solid construction waste and operational waste from vehicle and equipment scrapping; and 8) transportation and traffic during construction and during operation on roadways with catenary lines and at the harbors. Since significant adverse environmental impacts were identified, mitigation measures were identified and applied. However, the March 2017 Final Program EIR concluded that the 2016 AQMP would have significant and unavoidable adverse environmental impacts even after mitigation measures were identified and applied. As such, mitigation measures were made a condition of project approval and a Mitigation, Monitoring, and Reporting Plan was adopted. Findings were made and a Statement of Overriding Considerations was adopted by the South Coast AQMD Governing Board.

[6] South Coast AQMD, Final Program Environmental Impact Report for the 2016 Air Quality Management Plan, March 2017. http://www.aqmd.gov/home/research/documents-reports/lead-agency-SCAQMD-projects/SCAQMD-projects---year-2017

PR 1109.1 primarily implements current BARCT which is statutorily required in California Health and Safety Code Section 40406 to consider "environmental, energy, and economic impacts." For a portion of the equipment and facilities that are subject to PR 1109.1, a BARCT analysis was previously conducted and completed for the amendments to the NOx RECLAIM program that were adopted on December 4, 2015. The December 2015 Final Program Environmental Assessment (PEA) for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (referred to herein as the December 2015 Final PEA for NOx RECLAIM)[7] evaluated the environmental impacts of implementing that BARCT analysis. To comply with the requirements in Health and Safety Code Sections 40440 and 39616 by conducting a BARCT assessment for the NOx RECLAIM program, the following amendments to Regulation XX were adopted: Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx); Rule 2005 – New Source Review For RECLAIM; Attachment C from Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Sulfur (SOx) Emissions; and Attachment C from Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Nitrogen (NOx) Emissions.

The December 2015 amendments to Regulation XX were developed to reduce emissions from equipment and processes operated at NOx RECLAIM facilities located throughout the entire South Coast AQMD jurisdiction. Under these amendments, the BARCT analysis found that it would be both feasible and cost-effective for facility operators to install new air pollution control equipment or modify existing air pollution control equipment at 20 facilities with 11 facilities belonging to the non-refinery sector and nine facilities belonging to the refinery sector. The December 2015 Final PEA for NOx RECLAIM analyzed the environmental impacts from installing new air pollution control equipment or modifying existing air pollution control equipment for the following types of equipment and processes: 1) fluid catalytic cracking units; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) sulfur recovery units – tail gas treatment units; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant internal combustion engines; 8) container glass melting furnaces; 9) coke calcining; and, 10) metal heat treating furnaces. Table 1.1-1 summarizes the potential NOx control technologies that were considered as part of implementing the December 2015 amendments to the NOx RECLAIM program and analyzed in the December 2015 Final PEA for NOx RECLAIM.

[7] South Coast AQMD, Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), SCH No. 2014121018/SCAQMD No. 12052014BAR, certified December 4, 2015. http://www.aqmd.gov/home/library/documents-support-material/lead-agency-scaqmd-projects/scaqmd-projects---year-2015.

Table 1.1-1
NOx Control Devices Per Sector and Equipment/Source Category as Analyzed in the December 2015 Final PEA for NOx RECLAIM

Sector	Equipment/Source Category	NOx Control Devices
Refinery	Fluid Catalytic Cracking Units (FCCUs)	SCR LoTOx™ with WGS LoTOx™ without WGS
Refinery	Refinery Process Heaters and Boilers	SCR
Refinery	Refinery Gas Turbines	SCR
Refinery	Sulfur Recovery Unit/Tail Gas Units (SRU/TGUs, SRU/TG, or SRU/TGTU)	SCR LoTOx™ with WGS
Refinery	Petroleum Coke Calciner	LoTOx™ with WGS UltraCat™ with DGS
Non-Refinery	Container Glass Melting Furnaces	SCR UltraCat™ with DGS
Non-Refinery	Sodium Silicate Furnaces	SCR UltraCat™ with DGS
Non-Refinery	Metal Heat Treating Furnaces	SCR
Non-Refinery	Internal Combustion Engines (Non-Refinery/Non-Power Plant)	SCR
Non-Refinery	Turbines (Non-Refinery/Non-Power Plant)	SCR

The programmatic analysis of the environmental impacts in the December 2015 Final PEA for NOx RECLAIM was based on projected NOx emission reductions resulting from reducing NOx allocations by up to 14 tons per day from the refinery and non-refinery sectors. Although reducing NOx emissions would provide an overall environmental benefit to air quality, the analysis in the December 2015 Final PEA for NOx RECLAIM concluded that activities facility operators could potentially implement to comply with the December 2015 NOx RECLAIM amendments would cause secondary adverse impacts. The December 2015 Final PEA for NOx RECLAIM concluded that the topics of air quality during construction and greenhouse gases (GHGs), hazards and hazardous materials (due to ammonia transportation), and hydrology (water demand) exceeded the South Coast AQMD's air quality significance thresholds associated with implementing the December 2015 amendments to the NOx RECLAIM program. Since significant adverse environmental impacts were identified, mitigation measures were identified and applied. However, the December 2015 Final PEA for NOx RECLAIM concluded that the December 2015 amendments to the NOx RECLAIM program would have significant and unavoidable adverse environmental impacts even after mitigation measures were identified and applied. As such, mitigation measures were made a condition of project approval and a Mitigation Monitoring Plan was adopted. Findings were made and a Statement of Overriding Considerations was adopted by the South Coast AQMD Governing Board.

PR 1109.1 applies to refineries and related industries, more facilities than were previously analyzed for the refinery sector in the December 2015 Final PEA for NOx RECLAIM, or originally contemplated in the March 2017 Final Program EIR for the 2016 AQMP for CMB-05 and the RECLAIM Transition project. PR 1109.1 also includes additional BARCT requirements for equipment categories and facilities[8] belonging to the refinery sector. Since the proposed project includes PR 429.1, PAR 1304, PAR 2005, and the proposed rescission of Rule 1109 as well, the CEQA analysis needs to be updated reflect this additional information.

Table 1.1-2 summarizes the equipment and source categories at petroleum refinery facilities and other related facilities that will be subject to PR 1109.1 BARCT requirements along with the potential NOx control technologies that may be employed to achieve the desired NOx emissions reductions.

Table 1.1-2
NOx Control Devices Per Sector and Equipment/Source Category Applicable to PR 1109.1

PR 1109.1 Equipment/Source Category	NOx Control Devices
Boilers	Ultra Low-NOx burners; SCR; or Combination of the above
Gas Turbines	SCR
Ground Level Flares	No additional control, but for units that exceed 20 hours per year, replacement with low-NOx flare
Fluid Catalytic Cracking Units (FCCUs)	SCR
Petroleum Coke Calciner	SCR; LoTOx™ with WGS; or UltraCat™ with DGS
Process Heaters	Ultra Low-NOx burners; SCR; or Combination of the above
Sulfur Recovery Unit / Tail Gas Units (SRU/TGUs)	Ultra Low-NOx burners (some currently meeting limit)
Steam Methane Reformer Heaters (without/with gas turbine)	Ultra Low-NOx burners; SCR; or Combination of the above
Sulfuric Acid Furnaces	Currently meeting limit
Vapor Incinerators	Ultra Low-NOx burners

Implementation of the proposed project is estimated to reduce NOx emissions by approximately seven to eight tons per day, without increasing CO emissions. In addition, the proposed project is estimated to decrease annual PM2.5 concentrations regionwide by ~~0.12~~ 0.11 μg/m^3. As explained earlier, the December 2015 amendments to the NOx RECLAIM program projected a total of 14 tons per day of NOx emission reductions from reducing NOx RTC allocations from refinery and non-refinery sectors. At the December 2015 public hearing, however, the South Coast AQMD Governing Board adopted a revised version of the NOx RECLAIM proposal with a reduced NOx RTC shave amount of 12 tons per day, weighted for BARCT, and a delayed implementation schedule. The analysis of the environmental impacts in the December 2015 Final PEA for NOx RECLAIM was based on what physical modifications would need to be made at the affected facilities in order to achieve the entire 14 tons per day of NOx emission reductions, with NOx emission reductions of 9.58 tons per day from the refinery sector and 4.42 tons per day from

[8] South Coast AQMD's rule development webpage for PR 1109.1 contains all of the documentation relied upon for the BARCT analysis and can be found here: http://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book/proposed-rules/rule-1109-1.

facilities in the non-refinery sector. However, after adjusting the total NOx emission reductions from the December 2015 NOx RECLAIM amendments to 12 tons per day, the portion of NOx emission reductions was adjusted accordingly to 8.21 tons per day from the refineries and 3.79 tons per day from facilities in the non-refinery sector.

When comparing the types of activities and associated environmental impacts with implementing the BARCT standards for the equipment and facilities subject to the December 2015 NOx RECLAIM amendments as identified in Table 1.1-1 that were previously analyzed in the December 2015 Final PEA for NOx RECLAIM, to the additional equipment and sources that will need to comply with the BARCT requirements in PR 1109.1 as identified in Table 1.1-2, the physical activities that facility operators may undertake to comply with the BARCT requirements in PR 1109.1 are expected to be the same and will cause the same type of secondary adverse environmental impacts affecting the same environmental topic areas that were identified and previously analyzed in the December 2015 Final PEA for NOx RECLAIM (e.g., air quality during construction and GHGs, hazards and hazardous materials due to ammonia, and hydrology (water demand).

Since PR 429.1, PAR 1304, PAR 2005, and the proposed rescission of Rule 1109 are rule development activities intended to provide support to the implementation of PR 1109.1, and do not themselves impose any emission reduction requirements, no physical modifications that would create any secondary adverse environmental impacts are expected to occur for this portion of the proposed project. PR 429.1 proposes new requirements for startup, shutdown, and certain maintenance events, including an exemption from the NOx and CO emission limits in PR 1109.1 during these events; and proposes notification and recordkeeping requirements for units that will be subject to PR 1109.1. PARs 1304 and 2005 propose a limited exemption to allow facilities implementing BARCT requirements pursuant to PR 1109.1 to focus on achieving NOx emission reductions without having to concurrently reduce the sulfur content in refinery fuel gas that would otherwise be required by BACT.

CEQA Guidelines Section 15187 requires South Coast AQMD to perform an environmental analysis when proposing to adopt a new rule or regulation requiring the installation of air pollution control equipment, or establishing a performance standard, which is the case with the proposed project. CEQA Guidelines 15187(c) requires the environmental analysis to include at least the following information:

- An analysis of reasonably foreseeable environmental impacts of the methods of compliance;
- An analysis of reasonably foreseeable mitigation measures relating to those environmental impacts; and
- An analysis of reasonably foreseeable alternative means of compliance with the rule or regulation, which would avoid or eliminate the identified environmental impacts.

The proposed project, PR 1109.1 in combination with supporting rules PR 429.1, PARs 1304 and 2005, and the proposed rescission of Rule 1109, is designed to amend the previous BARCT assessments conducted for: 1) facilities in the refinery sector as previously analyzed in the December 2015 Final PEA for NOx RECLAIM; and 2) Control Measure CMB-05 and the entire RECLAIM Transition project in the 2016 AQMP as previously analyzed in the March 2017 Final Program EIR for the 2016 AQMP.

In analyzing the potential environmental impacts as required by CEQA Guidelines Section 15187, South Coast AQMD staff has determined that the proposed project contains new information of substantial importance which was not known and could not have been known at the time of certification of: 1) the December 2015 Final PEA for NOx RECLAIM; and 2) the March 2017 Final Program EIR for the 2016 AQMP [CEQA Guidelines Section 15162(a)(3)]. Thus, the analysis indicates that the type of CEQA document appropriate for the proposed project is a Subsequent Environmental Assessment (SEA), which contains the environmental analysis required by CEQA Guidelines Section 15187 and tiers off of the December 2015 Final PEA for NOx RECLAIM and the March 2017 Final Program EIR for the 2016 AQMP as allowed by CEQA Guidelines Sections 15152, 15162, 15168, and 15385. This SEA is a subsequent document to the December 2015 Final PEA for NOx RECLAIM.

Because this is a subsequent document, the baseline is the project analyzed in the December 2015 Final PEA for NOx RECLAIM. Specifically, the proposed project is expected to substantially increase the severity of the significant effects that were previously examined in the December 2015 Final PEA for NOx RECLAIM. [CEQA Guidelines Section 15162(a)(3)(B)].

The SEA is a substitute CEQA document prepared in lieu of a Subsequent EIR with significant impacts [CEQA Guidelines Section 15162], pursuant to the South Coast AQMD's Certified Regulatory Program [CEQA Guidelines Section 15251(1)]; codified in South Coast AQMD Rule 110. The SEA is also a public disclosure document intended to: 1) provide the lead agency, responsible agencies, decision makers, and the general public with information on the environmental impacts of the proposed project; and 2) be used as a tool by decision makers to facilitate decision making on the proposed project.

Thus, the South Coast AQMD, as lead agency for the proposed project has prepared this SEA with significant impacts. In addition, since significant adverse impacts have been identified, an alternatives analysis and mitigation measures are required and have been included in this SEA.

The Draft SEA has been ~~is being~~ released and circulated for a 46-day public review and comment period from September 31, 2021 to October 19, 2021. Five comment letters were received during the comment period and one comment letter was received after the close of the comment period. The comments and responses relative to the Draft SEA are included in Appendix F of this Final SEA.~~Any comments on the analysis presented in this Draft SEA received during the public comment period will be responded to and included in an appendix of the Final SEA.~~

The December 2015 Final PEA for NOx RECLAIM (State Clearinghouse No. 2014121018) and the March 2017 Final Program EIR for the 2016 AQMP (State Clearinghouse No. 2016071006), upon which this SEA relies, are incorporated by reference pursuant to CEQA Guidelines Section 15150 and are available from the South Coast AQMD's website at:

December 2015 Final PEA for NOx RECLAIM:
http://www.aqmd.gov/home/research/documents-reports/lead-agency-scaqmd-projects/scaqmd-projects---year-2015

March 2017 Final Program EIR for the 2016 AQMP:
http://www.aqmd.gov/home/research/documents-reports/lead-agency-scaqmd-projects/scaqmd-projects---year-2017

The above documents may also be obtained from the South Coast AQMD's Public Information Center by calling (909) 396-2039 or by email PICrequests@aqmd.gov, or by contacting Derrick Alatorre - Deputy Executive Officer/Public Advisor, South Coast AQMD, 21865 Copley Drive, Diamond Bar, CA 91765, (909) 396-2432, dalatorre@aqmd.gov.

South Coast AQMD staff has reviewed the modifications made to the proposed project after the release of the Draft SEA for public review and comment and concluded that none of the revisions constitute significant new information, because: 1) no new significant environmental impacts would result from the proposed project; 2) there is no substantial increase in the severity of an environmental impact; 3) no other feasible project alternative or mitigation measure was identified that would clearly lessen the environmental impacts of the project and was considerably different from others previously analyzed, and 4) the Draft SEA did not deprive the public from meaningful review and comment. In addition, revisions to the proposed project and analysis in response to verbal or written comments during the rule development process would not create new, avoidable significant effects. As a result, these revisions do not require recirculation of the Draft SEA pursuant to CEQA Guidelines Sections 15073.5 and 15088.5. Therefore, the Draft SEA has been revised to include the aforementioned modifications such that it is now the Final SEA.

Prior to making a decision on the adoption of the proposed project, the South Coast AQMD Governing Board must review and certify the Final SEA, including responses to comments, as providing adequate information on the potential adverse environmental impacts that may occur as a result of adopting PR 1109.1, PR 429.1, amending PAR 1304 and PAR 2005, and rescinding Rule 1109.

1.2 PREVIOUS CEQA DOCUMENTATION

South Coast AQMD rules, as ongoing regulatory programs, have the potential to be revised over time due to a variety of factors (e.g., regulatory decisions by other agencies, new data, lack of progress in advancing the effectiveness of control technologies to comply with requirements in technology forcing rules, new more stringent national ambient air quality standards, etc.). PR 1109.1, a new rule with no previous CEQA documentation available, has been developed as a command-and-control landing rule for NOx RECLAIM facilities in accordance with the commitment made by Control Measure CMB-05 in the 2016 AQMP. South Coast AQMD staff uses the term "landing rules" to refer to rules setting BARCT limits that must be met by facilities currently in the RECLAIM program as they transition out of RECLAIM. PR 429.1, also a new rule with no previous CEQA documentation available, has been developed to address to address emissions that may occur during the start-up or shutdown of a PR 1109.1 combustion unit and/or its associated air pollution control equipment due to the lack of steady-state conditions.

PARs 1304 and 2005 were developed to address the NSR issues associated with potential emission increases of PM10 and SOx from the installation of new or modified SCR technology to comply with the proposed BARCT standards in PR 1109.1. There is no previous CEQA documentation for these rules that is germane to the proposed project.

Finally, because the proposed adoption of PR 1109.1 will make existing Rule 1109 outdated and no longer necessary, Rule 1109 is proposed to be rescinded. There is no previous CEQA documentation for this rule that is germane to the proposed project.

The proposed project, therefore, is integrally related to the December 2015 amendments to Regulation XX and Control Measure CMB-05 of the 2016 AQMP for which two previous environmental analyses have been prepared: the December 2015 Final PEA for NOx RECLAIM and the March 2017 Final Program EIR for 2016 AQMP.

The following summarizes the contents of these CEQA documents.

Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market; December 2015: To comply with the requirements in Health and Safety Code Sections 40440 and 39616 by conducting a BARCT assessment, amendments were adopted to the following rules which are part of Regulation XX: Rule 2002 – Allocations for Oxides of Nitrogen and Oxides of Sulfur; Rule 2005 – New Source Review For RECLAIM; Attachment C from Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Sulfur Emissions; and Attachment C from Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Nitrogen Emissions. The amendments were anticipated to reduce emissions from equipment and processes operated at NOx RECLAIM facilities located throughout the entire South Coast AQMD jurisdiction. In particular, the environmental impacts from these amendments were due to the potential for facilities installing new, or modifying existing control equipment for the following types of equipment/source categories in the NOx RECLAIM program: 1) fluid catalytic cracking units; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) sulfur recovery units – tail gas treatment units; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant internal combustion engines; 8) container glass melting furnaces; 9) coke calcining; and 10) metal heat treating furnaces. For clarity and consistency throughout the regulation, other minor revisions were also adopted. The amendments were designed to incrementally achieve an overall NOx emission reduction (reduction in RTCs allocated) of 14 tons per day from 2016 to 2022. The Initial Study identified the following environmental topics as areas that may be adversely affected by the proposed project: aesthetics; air quality and greenhouse gas emissions; energy; hazards and hazardous materials; hydrology and water quality; solid and hazardous waste; and, transportation and traffic. Further analysis of these environmental areas in the Final PEA concluded that only the topics of air quality and GHGs, hazards and hazardous materials (due to ammonia transportation), and hydrology (water demand) exceeded the South Coast AQMD's significance thresholds associated with implementing the project. Since significant adverse environmental impacts were identified, an alternatives analysis was required by CEQA and prepared. The December 2015 Final PEA concluded that the project would have significant and unavoidable adverse environmental impacts even after mitigation measures were identified and applied. As such, mitigation measures were made a condition of the approval of the project and a Mitigation Monitoring Plan was adopted. Findings were made and a Statement of Overriding Considerations was adopted. On December 4, 2015, the South Coast AQMD Governing Board certified the Final PEA which analyzed the project in its entirety as originally proposed at the Public Hearing. The December 2015 Final PEA can be obtained by visiting the South Coast AQMD website at: http://www.aqmd.gov/home/research/documents-reports/lead-agency-scaqmd-projects/scaqmd-projects---year-2015. The Findings, Statement of Overriding Considerations and Mitigation Monitoring Plan can be obtained by visiting the South Coast AQMD website at: http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2015/regxxfindings.pdf.

At the Public Hearing, the South Coast AQMD Governing Board adopted a revised version of the project with a reduced shave amount and a delayed implementation schedule, as follows:

1. The shave amount was reduced from 14 tons per day as originally proposed by South Coast AQMD staff, to 12 tons per day of NOx RTCs, weighted for BARCT, with the following modified implementation schedule:

   2016: 2 tons per day (instead of 4 tons per day)

   2017: 0 ton per day

   2018: 1 ton per day (instead of 2 tons per day)

   2019: 1 ton per day (instead of 2 tons per day)

   2020: 2 tons per day

   2021: 2 tons per day

   2022: 4 tons per day (instead of 2 tons per day)

2. The adjustment factors in the December 4, 2015 version of Rule 2002, subparagraphs (f)(1)(B) and (f)(1)(C), were modified to reflect the reduction to 12 tons per day NOx RTCs per the modified implementation schedule.

In addition, the South Coast AQMD Governing Board elected to not adopt proposed subdivision (i) of Rule 2002 which would have, if adopted, required RTCs to be retired for any facility that undergoes a complete shutdown or if equipment that represents more than 25 percent of facility emissions is shutdown. Instead, staff was instructed by the South Coast AQMD Governing Board to return to the NOx RECLAIM Working Group to further discuss and analyze what the potential implications of retiring and removing shutdown RTCs from the market would have on the entire NOx RECLAIM program and to develop a proposed project that would ensure a closer alignment of the treatment of shutdown RTCs in RECLAIM to command-and-control regulations. Following this process, staff was instructed to bring either the December 2015 proposal for Rule 2002 (i) or some other alternate proposal back to the South Coast AQMD Governing Board for consideration for adoption. On October 7, 2016, amendments to Rule 2002 were adopted by the South Coast AQMD Governing Board that addressed the treatment of RTCs upon NOx RECLAIM facility shutdowns.

Final Program Environmental Impact Report for the 2016 Air Quality Management Plan; March 2017: The 2016 AQMP identified control measures and strategies to bring the region into attainment with the revoked 1997 8-hour NAAQS (standard) (80 parts per billion (ppb)) for ozone by 2024; the 2008 8-hour ozone standard (75 ppb) by 2032; the 2012 annual PM2.5 standard (12 micrograms per cubic meter ($\mu g/m^3$)) by 2025; the 2006 24-hour PM2.5 standard (35 $\mu g/m^3$) by 2019; and the revoked 1979 1-hour ozone standard (120 ppb) by 2023. The 2016 AQMP consists of three components: 1) the South Coast AQMD's Stationary, Area, and Mobile Source Control Measures; 2) State and Federal Control Measures provided by the California Air Resources Board; and 3) Regional Transportation Strategy and Control Measures provided by the Southern California Association of Governments. The 2016 AQMP includes emission inventories and control measures for stationary, area, and mobile sources, the most current air quality setting, updated growth projections, new modeling techniques, demonstrations of compliance with state and federal Clean Air Act requirements, and an implementation schedule for adoption of the proposed control strategy. A Final Program EIR was prepared for the project which identified potential adverse impacts that may result from implementing the project for the following environmental topic areas: 1) aesthetics; 2) air quality and GHGs; 3) energy; 4) hazards and hazardous materials; 5) hydrology and water quality; 6) noise; 7) solid and hazardous waste; and 8) transportation and traffic. The analysis concluded that significant and unavoidable adverse environmental impacts from the project are expected to occur after implementing mitigation measures for the following environmental topic areas: 1) aesthetics from increased glare and from the construction and operation of catenary lines and use of bonnet technology for ships; 2) construction air quality and GHGs; 3) energy (due to increased electricity demand); 4) hazards and hazardous materials due to: (a) increased flammability of solvents; (b) storage, accidental release and transportation of ammonia; (c) storage and transportation of liquefied natural gas (LNG); and (d) proximity to schools; 5) hydrology (water demand); 6) construction noise and vibration; 7) solid construction waste and operational waste from vehicle and equipment scrapping; and 8) transportation and traffic during construction and during operation on roadways with catenary lines and at the harbors. Since significant adverse environmental impacts were identified, an alternatives analysis was required by CEQA and prepared. The March 2017 Final Program EIR concluded that the project would have significant and unavoidable adverse environmental impacts even after mitigation measures were identified and applied. As such, mitigation measures were made a condition of the approval of the project and a Mitigation, Monitoring, and Reporting Plan was adopted. Findings were made and a Statement of Overriding Considerations was adopted. The South Coast AQMD Governing Board certified the Final Program EIR and approved the project on March 3, 2017. The March 2017 Final Program EIR can be obtained by visiting the South Coast AQMD website at: http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2016/2016aqmpfpeir.pdf. The Findings, Statement of Overriding Considerations and Mitigation, Monitoring, and Reporting Plan can be obtained by visiting the South Coast AQMD website at: http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2017/att2toresolutionfor-2016aqmp.pdf.

1.3 INTENDED USES OF THIS DOCUMENT

In general, a CEQA document is an informational document that informs a public agency's decision-makers and the public generally of potentially significant adverse environmental effects of a project, identifies possible ways to avoid or minimize the significant effects, and describes reasonable alternatives to the project [CEQA Guidelines Section 15121]. A public agency's decision-makers must consider the information in a CEQA document prior to making a decision on the project. Accordingly, this SEA is intended to: a) provide the South Coast AQMD Governing Board and the public with information on the environmental effects of the proposed project; and b) be used as a tool by the South Coast AQMD Governing Board to facilitate decision-making on the proposed project.

Additionally, CEQA Guidelines Section 15124(d)(1) requires a public agency to identify the following specific types of intended uses of a CEQA document:

1. A list of the agencies that are expected to use the SEA in their decision-making;
2. A list of permits and other approvals required to implement the project; and
3. A list of related environmental review and consultation requirements required by federal, state, or local laws, regulations, or policies.

In addition to the South Coast AQMD's Governing Board, which will consider the SEA for the proposed project in their decision-making, the California Air Resources Board (CARB), a state agency, and the U.S. EPA, a federal agency, will be reviewing the proposed project and all supporting documents, including the SEA, as part of the process for considering the inclusion of PR 1109.1, PR 429.1, PAR 1304, and PAR 2005 into the SIP, and removing Proposed Rescinded Rule 1109 from the SIP. Moreover, the proposed project is not subject to any other related environmental review or consultation requirements.

To the extent that local public agencies, such as cities, county planning commissions, et cetera, are responsible for making land use and planning decisions related to projects that must comply with the requirements in the proposed project, they could possibly rely on this SEA during their decision-making process.

For any affected facility operator who proposes to install air pollution control equipment and other components necessary to the installation of that equipment for the purpose of complying with the BARCT emission standards in the proposed project, South Coast AQMD permit applications and a CEQA Review would be required to determine if the project could rely on this SEA or if further CEQA analysis is warranted before any approvals can be granted.

Each of the individual facility's air pollution reduction projects necessary to implement the requirements of PR 1109.1 would likely require at least one permit from South Coast AQMD to construct air pollution control equipment, replace equipment, or both. Also, many of these facility-specific projects are likely to require building permits and possibly other permits from their local agencies. Since it is uncertain exactly which air pollution control technologies will be selected for each facilities air pollution reduction project, it is not feasible to identify all applicable local agency permits that may be required in the future.

This proposed project will be reviewed by both CARB and the U.S. EPA to determine if PRs 1109.1 and 429.1, and PARs 1304 and 2005 should be approved into the state implementation plan (SIP) and the proposed rescission of Rule 1109 should be removed from the SIP as required under the Clean Air Act. The U.S. EPA's approval is subject to a public review process generally of at least 30 days after publication in the Federal Register. South Coast AQMD staff is not aware of any additional environmental review or consultation requirements to carry out the emission reduction projects necessary to implement these rules, except that the local lead agency may determine that further CEQA analysis is necessary, depending on the specifics of those future projects.

1.4 AREAS OF CONTROVERSY

CEQA Guidelines Section 15123(b)(2) requires a public agency to identify the areas of controversy in the CEQA document, including issues raised by agencies and the public. Over the course of developing the proposed project, the predominant concerns expressed by representatives of industry and environmental groups, either in public meetings or in written comments, regarding the proposed project are highlighted in Table 1.4-1.

Table 1.4-1
Areas of Controversy

	Area of Controversy	Topics Raised by the Public	South Coast AQMD Evaluation
1.	Technical Feasibility and Cost Effectiveness	BARCT levels have not been proven to be technologically feasible and cost effective	• Technical feasibility and cost-effectiveness assessments have been conducted for each class and category of equipment subject to PR 1109.1. • Details of the assessments were presented during Working Group Meetings and stakeholders were invited to provide input on South Coast AQMD staff's conclusions. • NOx limits are technically feasible through established, proven control technology such as SCR, ULNBs, or a combination of both, LoTOx™ with WGS, and UltraCat™ with DGS. • Proposed NOx limits seek the highest level of NOx emission reductions that were demonstrated to be cost-effective. • Staff relied on stakeholder feedback (e.g., project cost estimates) and the U.S. EPA SCR spreadsheet modified to reflect refineries at California labor rates to estimate costs.
2.	Averaging Times	Proposed averaging time for heaters and boilers is too long and will allow for higher emissions	Factors considered when establishing averaging times: • Equipment stability (e.g., burner control); • Complex control technology requires a balance of operating parameters; • Operators must optimize and balance the NOx, ammonia, and CO emissions; • Complex operations with multiple pieces of equipment • Varying feedstock and use of refinery fuel gas (as opposed to natural gas); • Adjustments for unit response time; • A 2-hour averaging period for units requiring burners replacement and source testing to demonstrate compliance; • A 24-hour averaging period for units requiring SCR and CEMS to demonstrate compliance; • A daily rolling 365-day averaging period for large process units, e.g., FCCU, petroleum coke calciner, with CEMS to demonstrate compliance; • Proposed averaging times supported by third party engineering consultants; and • Longer averaging times were needed for the low-NOx limits to be technically feasible; shorter averaging times would have resulted in higher -NOx limits and therefore higher emissions.
3.	Start-up, Shutdown, and	SSM provisions will allow excess emissions	Starting up and shutting down equipment are necessary actions as part of operations, and in some cases, unavoidable:

	Area of Controversy	Topics Raised by the Public	South Coast AQMD Evaluation
	Malfunction (SSM)		• Time and temperature are needed for SCR control equipment to achieve NOx reduction and operate effectively. • Equipment without SCR needs time to reach optimal unit operating temperatures. • PR 429.1, a companion rule to PR 1109.1, proposes to exempt units during startup and shutdown events and establish limits on the duration and number of allowable start-up and shutdown events in order to minimize emissions.
4.	Implementation Schedule in PR 1109.1	Longer time should be provided for each phase of the implementation schedule	• PR 1109.1 establishes various implementation options for facilities to meet emission reduction targets at different deadlines. • Implementation schedule accounts for the variability that could occur during the process (e.g., permitting time). • Implementation schedule recognizes the time needed to design, engineer, budget, order, deliver, logistics, install, and commission, in order to properly meet a scheduled turnaround. • Staff has provided additional time and flexibility in the schedules for implementing the emission control projects, including provisions for an extension of the schedule.
5.	CEQA process and Type of CEQA document to prepare	Preparing a CEQA document that tiers off of the previous analyses in the December 2015 Final PEA for NOx RECLAIM and the March 2017 Final Program EIR for the 2016 AQMP would be considered piecemealing and inappropriate under CEQA because: • The 2016 AQMP and CMB-05 did not contemplate sunsetting of the RECLAIM program and the March 2017 Final Program EIR for the 2016 AQMP did not analyze	When initially considering how to "unwind" the RECLAIM regulation and transition NOx RECLAIM equipment to a command-and-control structure subject to various landing rules in Regulation XI, South Coast AQMD staff previously received similar comments regarding South Coast AQMD's practice in conducting CEQA analyses for rule projects, including the command-and-control landing rules. CEQA Guidelines Section 15187 requires an environmental analysis to be performed when a public agency proposes to adopt a new rule or regulation requiring the installation of air pollution control equipment or establishing a performance standard, which is the case with the proposed project. This approach does not amount to piecemealing because the documents being tiered off of considered the environmental impacts of the projected emission reductions for all of the sources in RECLAIM, thus considering the environmental effects of all of the rules proposed to implement BARCT requirements on RECLAIM sources ("landing rules"). This SEA considers impacts that may not have been considered in the documents being tiered off of. Each landing rule is a separate and individual project with independent utility. Each landing rule undergoes its own CEQA analysis to address any impacts that were not addressed in one or more prior CEQA documents. All

		the sunsetting of the RECLAIM program. • The December 2015 amendments to the NOx RECLAIM program and the December 2015 Final PEA for NOx RECLAIM did not analyze what is being contemplated by the proposed project. • The impacts that are associated with the proposed project and other implementation issues (e.g., NSR) were not identified or contemplated at the time the decision was made to replace the NOx RECLAIM program with individual BARCT command-and-control rules.	South Coast AQMD rules and regulations are related to each other in that they are adopted and/or amended to meet the clean air goals outlined in the 2016 AQMP, but that does not mean they constitute a single project for CEQA purposes. The CEQA document for the 2016 AQMP, the March 2017 Final Program EIR, contains the programmatic analyses of the overall effects of South Coast AQMD's clean air goals. The decision to transition from NOx RECLAIM into a source-specific command-and-control regulatory structure was approved by the South Coast AQMD Governing Board as Control Measure CMB-05 in the 2016 AQMP. CMB-05 is required by the California Health and Safety Code to implement BARCT in lieu of the RECLAIM program, which will be completed upon each individual rule amendment or the adoption of various landing rules. The California Health and Safety Code also requires other stationary sources to meet BARCT so the landing rules may also apply to non-RECLAIM sources. CMB-05 identifies a series of approaches that can be explored to make the RECLAIM program more effective in ensuring equivalency with command-and-control regulations implementing BARCT and to generate further NOx emissions reductions at RECLAIM facilities, including sunsetting the RECLAIM program. CMB-05 specifically contemplates the unwinding of the RECLAIM program (see Final 2016 AQMP, Appendix IV-A, pp. IV-A-67 to IV-A-71)[9]. The commenter has failed to identify any type of environmental impact that would result from the sunsetting of RECLAIM that was not discussed in the documents being tiered off of. The Revised Draft Program EIR for the 2016 AQMP did contemplate the sunsetting of RECLAIM, since in the Revised Draft 2016 AQMP that was released in October 2016[10], Control Measure CMB-05 was revised to include the following language: *"One approach under serious consideration is a long-term transition to a traditional command-and-control regulatory structure. As many of the program's original advantages appear to be diminishing and generating increased scrutiny, an orderly sunset of the RECLAIM program may be the best way to create more regulatory certainty and reduce compliance burdens for RECLAIM facilities, while also achieving more actual and SIP creditable emissions reductions."* Thus, the March 2017 Final Program EIR for the 2016 AQMP analyzed Control Measure CMB-05, which contemplated the potential for sunsetting the RECLAIM program, even though the final decision was not made until the adoption of the 2016 AQMP at the March 2017 Governing Board hearing.

Area of Controversy	Topics Raised by the Public	South Coast AQMD Evaluation
		Furthermore, a program-level analysis of the potential environmental impacts associated with the 2016 AQMP, including CMB-05 and the entire RECLAIM Transition project, were specifically analyzed in the March 2017 Final Program EIR. In particular, the March 2017 Final Program EIR for the 2016 AQMP addressed the environmental effects of reasonably foreseeable environmental consequences for the RECLAIM Transition project and determined that the overall implementation has the potential to generate adverse environmental impacts to seven topic areas: air quality; energy; hazards and hazardous materials; hydrology and water quality; noise; solid and hazardous waste; and transportation. More specifically, the March 2017 Final Program EIR for the 2016 AQMP evaluated and identified the impacts from the installation and operation of additional control equipment, such as SCR equipment, potentially resulting in construction emissions, increased electricity demand, hazards from the additional ammonia transport and use, increase in water use and wastewater discharge, changes in noise volume, generation of solid waste from construction and disposal of old equipment and catalyst replacements, as well as changes in traffic patterns and volume. The time to challenge the assessments for the analyses of March 2017 Final Program EIR for the 2016 AQMP relied upon has passed (see Public Resources Code Sections 21167 and 21167.2). Since the South Coast AQMD has already prepared a program level analysis for the 2016 AQMP, which included the RECLAIM Transition, no additional program-level analysis is required and further analyses for the landing rules, including the rules that comprise the proposed project, have been tiered-off of the 2016 AQMP EIR. [CEQA Guidelines Section 15168; Al Larson Boat Shop, Inc. v. Board of Harbor Commissioners (1993) 18 Cal.App.4th 729, 740-41.] As such, the South Coast AQMD has and will continue to evaluate each individual RECLAIM Transition rule that is developed pursuant to the 2016 AQMP, to determine if any additional CEQA review is required. [CEQA Guidelines Section 15168]. Additional analysis could include the preparation of a project-level EIR or Subsequent EIR to the March 2017 Final Program EIR for the 2016 AQMP. [CEQA Guidelines Section 15161 and 15162]. Moreover,

9 South Coast AQMD. Final 2016 AQMP, Appendix IV-A, pp. IV-A-67 to IV-A-71. http://www.aqmd.gov/docs/defaultsource/clean-air-plans/air-quality-management-plans/2016-air-quality-management-plan/final2016-aqmp/appendix-iv-a.pdf

10 Revised Draft 2016 AQMP, Appendix IV-A, October 2016, p. IV-A-84.

Area of Controversy	Topics Raised by the Public	South Coast AQMD Evaluation
		streamlined environmental review pursuant to a Program EIR and tiering is consistent with South Coast AQMD's past practice as it is expressly allowed in CEQA and is not considered piecemealing. [CEQA Guidelines Sections 15152, 15162, 15165, 15168 and 15385]. This point is also explained in South Coast AQMD's response letter to BizFed on April 25, 2018[11]. To date, the following separate rule developments and have been conducted and completed for several RECLAIM Transition landing rules and the type of CEQA documents prepared and certified are subsequent CEQA analyses which tier off of the March 2017 Final Program EIR for the 2016 AQMP: • Final SEA for Rules 2001 and 2002 (certified on October 5, 2018)[12] • Final Mitigated SEA for Rule 1135 (certified on November 2, 2018)[13] • Final SEA for Rules 1146, 1146.1, 1146.2 and 1100 (certified on December 7, 2018)[14] • Final SEA for Rule 1134 (certified on April 5, 2019)[15] • Final SEA for Rules 1110.2 and 1100 (certified on November 1, 2019)[16] Thus, for the proposed project comprised of PRs 1109.1 and 429.1, PARs 1304 and 2005, and the proposed rescission of Rule 1109, South Coast AQMD has prepared this SEA which also tiers off of the March 2017 Final Program EIR for the 2016 AQMP. In addition, this SEA tiers off of the December 2015 Final Program EA for NOx RECLAIM because the majority of refinery-sector

[11] South Coast AQMD, Regulation XX – NOx RECLAIM, South Coast AQMD Response to BizFed – April 25, 2018. http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/5_response-042518_bizfed-letter.pdf.

[12] South Coast AQMD, Final Subsequent Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM): Proposed Amended Rule 2001 – Applicability, and Proposed Amended Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx), October 2018. http://www.aqmd.gov/docs/defaultsource/ceqa/documents/aqmd-projects/2018/finalseaforpars2001-2002-fullmerge.pdf.

[13] South Coast AQMD, Final Mitigated Subsequent Environmental Assessment for Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities, October 2018. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2018/par-1135---final-mitigated-sea_with-appendices.pdf.

[14] South Coast AQMD, Final Subsequent Environmental Assessment for Proposed Amended Rules 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters; 1146.1 – Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters; 1146.2 - Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters; and Proposed Rule 1100 – Implementation Schedule for NOx Facilities, November 2018. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2018/pars-1146-series---final-sea---full-merge-113018.pdf.

[15] South Coast AQMD, Final Subsequent Environmental Assessment for Proposed Amended Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines, March 2019. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2019/par-1134---final-sea_with_appdx.pdf.

[16] South Coast AQMD, Final Subsequent Environmental Assessment for Proposed Amended Rule 1110.2 – Emissions from Gaseous-and Liquid-Fueled Engines and Proposed Amended Rule 1100 – Implementation Schedule for NOx Facilities, October 2019. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2019/par-1110-2_final-sea_with-appx.pdf.

	Area of Controversy	Topics Raised by the Public	South Coast AQMD Evaluation
			facilities and equipment that were previously analyzed in December 2015 Final Program EA for NOx RECLAIM may be also be affected by the proposed project.
6.	Pollutants allowed to be exempt from BACT under PAR 1304	Extend applicability of the BACT exemption to CO.	The proposed narrow BACT exemption is intended to address PM10 and SOx emissions increases associated with add-on air pollution control equipment required to transition NOx RECLAIM and would trigger refinery fuel gas clean up. CO emissions would not trigger fuel gas clean up.
7.	Facilities qualified to use the limited BACT exemption under PAR 1304	Extend applicability of BACT exemption to non-RECLAIM facilities complying with a NOx BARCT limit for landing rule.	The objective of the proposed BACT exemption is to address the co-pollutant PM emissions tied to the installation of controls and the replacement of equipment that is combined with an installation or modification of add-on air pollution control required to transition NOx RECLAIM and therefore cannot be extended to non-RECLAIM facilities as it would result in an SB 288 issue.
8.	Projects qualified to use the limited BACT exemption under PAR 1304	The exemption should be expanded to include all related BARCT projects, not only those involving installation of add-on air pollution control equipment.	The BACT exemption is limited to projects associated with add-on air pollution control equipment since the exemption is needed to address the co-pollutant PM emissions, which are due to the ammonium sulfate formed from the SCR ammonia slip and the sulfur in the refinery fuel gas. Use of SCR systems is needed to ensure that cost-effective NOx levels can be achieved under PR 1109.1. Without the limited BACT exemption, then higher NOx concentration limits without the use of SCR systems would need to be considered for PR 1109.1. Installations of equipment not associated with add-on air pollution control equipment will be required to meet BACT including possible refinery gas clean up.
9.	Criteria for equipment replacements allowed to use the PAR 1304 BACT exemption	The district should clarify that replacing units within different source categories meets the requirement to "serve the same purpose" for example, a facility may choose to replace a gas	The criteria to require that a replacement serve the same purpose as the unit being replaced was developed according to the federal NSR definition for a replacement in 40 CFR 51.165(a)(1)(xxi) and 40 CFR 52.21(b)(33). Under federal NSR, a replacement must be identical to or functionally equivalent[17] to the replaced unit and not alter the basic design parameters.[18] A functionally equivalent unit was previously defined to be a unit that serves the same purpose as the replaced unit.[19] The federal NSR definition for a replacement requires that replacing a unit with a unit from a different source category that serves the same purpose would need to have the same basic design parameters. Units from different source categories, such as

[17] 40 CFR 51.165(a)(1)(xliv) and 40 CFR 52.21(b)(56) are the vacated provisions that defined functionally equivalent component

[18] 40 CFR 51.165(h)(2) and 40 CFR 52.21(cc)(2) are the vacated provisions that defined basic design parameters

[19] The definitions of functionally equivalent component and basic design parameters were vacated. However, even though these definitions were removed, they can still be used as guidance to define replacements. See 86 FR 37918 stating: "However, while not controlling, the EPA and stakeholders may continue to look to the vacated definitions from the ERP rule to guide their understanding of the definition of replacement unit."

Area of Controversy	Topics Raised by the Public	South Coast AQMD Evaluation
	turbine with a boiler.	a turbine and a boiler, would not have the same basic design parameters. The PAR 1304 BACT exemption can be used for situations where a unit will be replaced with a new unit from a different source category (e.g., a boiler for a turbine). If the new unit is installed to meet a NOx BARCT limit and serves the same purpose, then the BACT exemption will not be restricted to require that the new unit be of the same source category. ~~The federal NSR definition for a replacement is used as the replacement criteria for the PAR 1304 BACT exemption, since u~~Under federal NSR, for a replacement unit, the baseline emissions are the actual emissions of the existing unit being replaced rather than a zero baseline if considered a new unit. However, a unit being replaced with a unit from a different source category would be considered a new emissions unit instead of a replacement unit since the unit would not meet the federal definition for a replacement. As a new emissions unit, federal major NSR applicability would be determined using a zero emissions baseline and the Actual-to-Potential test. If the unit treated as a new unit qualifies as a major modification, then it would not be able to use the BACT exemption in PAR 1304.

Pursuant to CEQA Guidelines Section 15131(a), "[e]conomic or social effects of a project shall not be treated as significant effects on the environment." CEQA Guidelines Section 15131(b) states further, "[e]conomic or social effects of a project may be used to determine the significance of physical changes caused by the project." Physical changes that may be caused by the proposed project have been evaluated in Chapter 4 of this Final ~~Draft~~ SEA. No direct or indirect physical changes resulting from economic or social effects have been identified as a result of implementing the proposed project.

1.5 EXECUTIVE SUMMARY

CEQA Guidelines Section 15123 requires a CEQA document to include a brief summary of the proposed actions and their consequences. In addition, areas of controversy must also be included in the executive summary (see preceding discussion). This SEA consists of the following chapters: Chapter 1 – Executive Summary; Chapter 2 – Project Description; Chapter 3 – Existing Setting, Chapter 4 –Environmental Impacts; Chapter 5 –Alternatives; Chapter 6 – References; Chapter 7 – Acronyms, and various appendices. The following subsections briefly summarize the contents of chapters 1 through 5.

Summary of Chapter 1 – Executive Summary

Chapter 1 includes an introduction of the proposed project and a discussion of the legislative authority that allows the South Coast AQMD to amend and adopt air pollution control rules, identifies general CEQA requirements and the intended uses of this CEQA document, and summarizes the remaining four chapters that comprise this SEA.

Summary of Chapter 2 – Project Description

South Coast AQMD staff has been directed by the Governing Board to begin the process of transitioning equipment at facilities that are currently subject to facility permit requirements per South Coast AQMD Regulation XX – RECLAIM for NOx to instead be subject to an equipment-based command-and-control regulatory structure per South Coast AQMD Regulation XI – Source Specific Standards. To date, several rules have been amended in accordance with the Governing Board's direction. Currently, South Coast AQMD staff is continuing this transition process by developing the proposed project which is comprised of PRs 1109.1 and 429.1, PARs 1304 and 2005, and proposed rescinded Rule 1109.

PR 1109.1 proposes to establish BARCT requirements to reduce NOx emissions while not increasing CO emissions from petroleum refineries and facilities with operations related to petroleum refineries which includes asphalt plants, biofuel plants, hydrogen production plants, facilities that operate petroleum coke calciners, sulfuric acid plants, and sulfur recovery plants. The following combustion equipment categories will be applicable to PR 1109.1: 1) boilers; 2) gas turbines; 3) ground level flares; 4) fluidized catalytic cracking units; 5) petroleum coke calciners; 6) process heaters; 7) sulfur recover units/tail gas treating units; 8) SMR heaters; 9) SMR heaters with gas turbine; 10) sulfuric acid furnaces; and 11) vapor incinerators. PR 1109.1 will transition affected equipment operating at 16 facilities, including nine petroleum refineries and facilities as petroleum refineries under common ownership, three small refineries, and four facilities with related operations, that are subject to the NOx RECLAIM program to a command-and-control regulatory structure. A list of affected facilities and equipment is provided in Appendix D of this Final ~~Draft~~ SEA.

During development of PR 1109.1, the issue of start-up and shutdown events was identified as a concern. When a unit or its associated air pollution control equipment starts or ceases operating, the equipment is not functioning at steady-state conditions and could potentially cause exceedances of NOx and CO emission limits during these intervals. To address this issue, PR 429.1 proposes new requirements for startup, shutdown, and certain maintenance events, including an exemption from the NOx and CO emission limits in PR 1109.1 during these events. PR 429.1 also proposes notification and recordkeeping requirements for units that will be subject to PR 1109.1.

To achieve the BARCT NOx concentration limits under PR 1109.1, installations or modifications of post-combustion air pollution control equipment such as SCRs and the replacement of burners with ULNBs are expected to occur. This equipment will reduce NOx emissions, but may also increase emissions of particulate matter and SOx, which may trigger BACT and require sulfur clean-up of the refinery fuel gas. PAR 1304 and PAR 2005 propose to include a narrow BACT exemption to address these potential emission increases associated with installation of new or the modification of existing post-combustion air pollution control equipment or other equipment modifications to comply with the proposed NOx emission limits in PR 1109.1.

Because the proposed adoption of PR 1109.1 will make Rule 1109 outdated and no longer necessary, Rule 1109 is proposed to be rescinded. Implementation of the proposed project is estimated to reduce NOx emissions by approximately 7 to 8 tons per day after implementation of the BARCT NOx concentration limits in PR 1109.1, and decrease annual PM2.5 concentrations regionwide by ~~0.12~~ 0.11 $\mu g/m^3$. These reductions in NOx emissions and PM2.5 concentration are expected to be achieved by retrofitting existing equipment with a variety of air pollution control equipment (e.g., SCR technology/systems, , LoTOx™ with and without WGSs, and UltraCat™ with DGSs), all of which are the same air pollution control equipment as previously evaluated in the

December 2015 Final PEA for NOx RECLAIM, as well as modifying combustion equipment by replacing existing burners with ULNBs.

While reducing emissions of NOx and other contaminants will create an environmental benefit, activities that facility operators may undertake to comply with the proposed project may also create secondary potentially significant adverse environmental impacts in the topics of air quality during construction and GHGs, hazards and hazardous materials during ammonia transportation, and hydrology due to water demand.

The development of the proposed project is a culmination of recommendations made throughout the public engagement process including input from the working group which is composed of representatives from the manufacturers, trade organizations, permit stakeholders, businesses, environmental groups, public agencies, consultants, and other interested parties. To date, 24 working group meetings have been held by the South Coast AQMD. In addition, South Coast AQMD staff has corresponded with and individually met with representatives of each of the affected facilities as well as environmental groups to discuss the proposed project. A Public Workshop will be held on September 1, 2021.

Appendix A of this Final ~~Draft~~ SEA contains a copy of PRs 1109.1 and 429.1, PARs 1304 and 2005, and proposed rescinded Rule 1109.

Summary of Chapter 3 – Existing Setting

Pursuant to CEQA Guidelines Section 15125, Chapter 3 – Existing Setting includes a description of the existing environmental setting of the environmental topic areas that are expected to have potentially significant adverse impacts if the proposed project is implemented.

The proposed project is comprised of PRs 1109.1 and 429.1, PARs 1304 and 2005, and proposed rescinded Rule 1109. The proposed project is designed to amend the previous BARCT assessments conducted for: 1) facilities in the refinery sector as previously analyzed in the December 2015 Final PEA for NOx RECLAIM; and 2) Control Measure CMB-05 and the entire RECLAIM Transition project in the 2016 AQMP as previously analyzed in the March 2017 Final Program EIR for the 2016 AQMP. This SEA tiers off of the December 2015 Final PEA for NOx RECLAIM and the March 2017 Final Program EIR for the 2016 AQMP as allowed by CEQA Guidelines Sections 15152, 15162, 15168, and 15385.

PR 1109.1 contains BARCT NOx concentration limits which are expected to be achieved primarily by installing new or modifying existing post-combustion air pollution control equipment, and utilization of various NOx emission control technologies is expected to create secondary adverse impacts which are analyzed in this CEQA document. PR 429.1 proposes new requirements for startup, shutdown, and certain maintenance events, including an exemption from the NOx and CO emission limits in PR 1109.1 during these events; and proposes notification and recordkeeping requirements for units that will be subject to PR 1109.1. PARs 1304 and 2005 propose a limited exemption to allow facilities implementing BARCT requirements pursuant to PR 1109.1 to focus on achieving NOx emission reductions without having to concurrently reduce the sulfur content in refinery fuel gas that would otherwise be required by BACT. Since PR 429.1, PAR 1304, PAR 2005, and the proposed rescission of Rule 1109 are rule development activities intended to provide support to the implementation of PR 1109.1, and do not themselves impose any emission reduction requirements, no physical modifications that would create any secondary adverse environmental impacts are expected to occur for this portion of the proposed project.

The existing environmental setting is the physical environmental conditions as they existed at the time the Notice of Preparation (NOP) was published, or if no NOP is published, at the time the environmental analysis is commenced [CEQA Guidelines Section 15125]. The NOP for the Draft PEA for NOx RECLAIM was published on December 5, 2014, while the NOP for the Draft Program EIR for the 2016 AQMP was published on July 5, 2016. The analysis in the December 2015 Final PEA for NOx RECLAIM contains a detailed analysis of the environmental setting and corresponding environmental effects of implementing BARCT for combustion equipment for specific refinery-sector facilities that are the focus of the BARCT assessment in PR 1109.1, while the March 2017 Final Program EIR for the 2016 AQMP contains a more generalized analysis of the environmental impacts associated with implementing BARCT Control Measure CMB-05 and the entire RECLAIM Transition project in the 2016 AQMP. When considering both of these previous CEQA documents to determine the existing environmental setting, the baseline that was established at the time the NOP was published for the Draft PEA for NOx RECLAIM (e.g., December 5, 2014) more directly corresponds to the currently proposed project since the affected facilities, the type of combustion equipment involved, and the physical impacts that may occur as a result of implementing the BARCT requirements in PR 1109.1 are expected to be the same or similar as the previous analysis. For this reason, the baseline is the project analyzed in the December 2015 Final PEA for NOx RECLAIM.

This SEA analyzes the incremental changes that may occur subsequent to the December 2015 Final PEA for NOx RECLAIM if proposed project is implemented. A subset of the NOx RECLAIM universe of refinery-sector facilities that would be affected by the proposed project (e.g. nine facilities), and their combustion equipment, and the forecasted air pollution control equipment and the potential secondary environmental impacts were previously programmatically analyzed in the December 2015 Final PEA for NOx RECLAIM. This document also analyzed impacts from non-refinery related emission reduction projects. The previously certified December 2015 Final PEA for NOx RECLAIM concluded that the following topics would have significant and unavoidable adverse environmental impacts: air quality during construction and GHGs, hazards and hazardous materials associated with ammonia, and hydrology due to water demand.

During the December 2015 amendments to the NOx RECLAIM program, there were seven refinery-sector facilities in the NOx RECLAIM universe that were not anticipated to retrofit their combustion equipment with NOx controls at that time; thus, these facilities were not previously analyzed in the December 2015 Final PEA for NOx RECLAIM. However, the proposed project contains BARCT requirements for combustion equipment operated at these seven refinery-sector facilities, and the analysis in this SEA indicates that these facilities, their combustion equipment, the forecasted air pollution control equipment (e.g., new and upgraded SCRs), and/or burner modifications to install ULNBs that may be implemented to achieve BARCT, and the potential secondary environmental impacts associated with installation and operation of the new and upgraded SCRs and burner replacements with ULNBs, are similar to the previous analysis December 2015 Final PEA for NOx RECLAIM. Thus, the proposed project is expected to have the same or similar significant effects that were previously examined in the December 2015 Final PEA for NOx RECLAIM but that will be substantially more severe than what was discussed. The analysis of these impacts is presented in Chapter 4.

In addition, the analysis in this SEA independently considered whether the proposed project would result in new significant impacts for any of the other environmental topic areas previously concluded in the December 2015 Final PEA for NOx RECLAIM to have either no significant impacts or less than significant impacts and none were identified. A description and the basis for this conclusion is included in Chapter 4 of this SEA.

Table 1.5-1 provides a summary of the environmental topic areas previously analyzed in the December 2015 Final PEA for NOx RECLAIM which were concluded to have significant and unavoidable impacts and their applicability to the proposed project.

Table 1.5-1
Applicability of Significant Impacts in the December 2015 Final PEA for NOx RECLAIM to the Proposed Project

ENVIRONMENTAL TOPIC AREA PREVIOUSLY CONCLUDED IN THE DECEMBER 2015 FINAL PEA FOR NOX RECLAIM AS SIGNIFICANT	REMAIN SIGNIFICANT FOR THE PROPOSED PROJECT
Air Quality during construction and GHGs	Overlapping construction activities and the associated emissions occurring at multiple facilities are expected to cause an exceedance in South Coast AQMD's air quality significance thresholds for construction if the proposed project is implemented. The GHG impacts from the combination of amortized construction emissions, plus operational emissions associated with electricity use, water use and conveyance, wastewater generated, and vehicle trips are expected to cause an exceedance in South Coast AQMD's GHG significance threshold if the proposed project is implemented.
Hazards and Hazardous Materials associated with ammonia	The analysis of the proposed project indicates that the deliveries of ammonia, a hazardous material, will be needed to support the function of air pollution control technology (e.g., SCR technology and UltraCat^{TM} with DGS) which are expected to be employed for certain combustion equipment subject to the proposed project.
Hydrology (water demand)	The analysis of the proposed project indicates that potentially significant quantities of additional water will be needed during: 1) hydrotesting of newly installed ammonia storage tanks prior to their operation; and 2) operation of air pollution control equipment that specifically utilize water (e.g., LoTOx^{TM} with WGS).

As such, Chapter 3 of this Final ~~Draft~~ SEA contains subchapters devoted to describing the existing setting for each environmental topic area identified as having potentially significant adverse environmental impacts in Table 1.5-1.

Summary of Chapter 4 – Environmental Impacts

CEQA Guidelines Section 15126(a) requires a CEQA document to identify and focus on the "significant environmental effects of the proposed project." Direct and indirect significant effects of the project on the environment shall be clearly identified and described, giving due consideration to both the short-term and long-term effects. In addition, CEQA Guidelines Section 15126(b) requires a CEQA document to identify the significant environmental effects that cannot be avoided if the proposed project is implemented. CEQA Guidelines Section 15126(c) also requires a CEQA document to consider and discuss the significant irreversible environmental changes that would be involved if the proposed project is implemented. Further, CEQA Guidelines Section 15126(e) requires a CEQA document to consider and discuss mitigation measures proposed to minimize the significant effects. Finally, CEQA Guidelines Section 15130 requires a CEQA document to discuss whether the proposed project has cumulative impacts. Chapter 4 considers and discusses each of these requirements.

The proposed project: PR 1109.1, in combination with supporting rules PR 429.1, PARs 1304 and 2005, and the proposed rescission of Rule 1109, is designed to amend the previous BARCT assessments conducted for: 1) facilities in the refinery sector as previously analyzed in the December 2015 Final PEA for NOx RECLAIM; and 2) Control Measure CMB-05 and the entire RECLAIM Transition project in the 2016 AQMP as previously analyzed in the March 2017 Final Program EIR for the 2016 AQMP. This SEA tiers off of the December 2015 Final PEA for NOx RECLAIM and the March 2017 Final Program EIR for the 2016 AQMP as allowed by CEQA Guidelines Sections 15152, 15162, 15168, and 15385.

As explained in the Summary of Chapter 3, the baseline is the project analyzed in the December 2015 Final PEA for NOx RECLAIM.

PR 1109.1 contains BARCT NOx concentration limits which are expected to be achieved primarily by installing new or modifying existing post-combustion air pollution control equipment, and utilization of various NOx emission control technologies is expected to create secondary adverse impacts which are analyzed in this CEQA document. PR 429.1 proposes new requirements for startup, shutdown, and certain maintenance events, including an exemption from the NOx and CO emission limits in PR 1109.1 during these events; and proposes notification and recordkeeping requirements for units that will be subject to PR 1109.1. PARs 1304 and 2005 propose a limited exemption to allow facilities implementing BARCT requirements pursuant to PR 1109.1 to focus on achieving NOx emission reductions without having to concurrently reduce the sulfur content in refinery fuel gas that would otherwise be required by BACT. Since PR 429.1, PAR 1304, PAR 2005, and the proposed rescission of Rule 1109 are rule development activities intended to provide support to the implementation of PR 1109.1, and do not themselves impose any emission reduction requirements, no physical modifications that would create any secondary adverse environmental impacts are expected to occur for this portion of the proposed project. Thus, this chapter compares the types of activities and associated environmental impacts with implementing the BARCT standards for the equipment and facilities previously analyzed in the December 2015 Final PEA for NOx RECLAIM, to the additional equipment and sources that will need to comply with the BARCT requirements in PR 1109.1.

This SEA is a comprehensive environmental document that programmatically analyzes potential incremental environmental impacts from implementing the proposed project relative to the existing setting established in the December 2015 Final PEA for NOx RECLAIM. The analysis examines petroleum refineries and related industries, equipment operating at those facilities, and the activities that facility operators would be expected to undertake to comply with the proposed project. All of the affected facilities are located within South Coast AQMD's jurisdiction, within Los Angeles County.

Potential Environmental Impacts Found To Be Significant

The NOP/IS for the Draft PEA for NOx RECLAIM identified the following environmental topic areas as having potentially significant adverse impacts that would require further analysis in the PEA: aesthetics, air quality and GHGs, energy, hazards and hazardous materials, hydrology and water quality, solid and hazardous waste, and transportation and traffic. The December 2015 Final PEA for NOx RECLAIM concluded that the environmental topic areas of aesthetics, air quality during operation, energy, water quality, solid and hazardous waste, and transportation and traffic would have less than significant impacts.

The December 2015 Final PEA for NOx RECLAIM also concluded that the following environmental topic areas would have significant and unavoidable adverse environmental impacts: air quality during construction and GHGs, hazards and hazardous materials associated with ammonia, and hydrology due to water demand.

The analysis independently considers whether the proposed project would result in new significant impacts for any environmental topic areas previously concluded in the December 2015 Final PEA for NOx RECLAIM to have either no significant impacts or less than significant impacts; however, none were identified. A description and the basis for this conclusion is also included in this chapter.

This chapter also independently considers the currently proposed project and analyzes the incremental changes, if any, relative to the baseline, which is the project analyzed in the December 2015 Final PEA for NOx RECLAIM. While seven additional facilities and additional equipment categories will apply to the proposed project when compared to the project analyzed in December 2015 Final PEA for NOx RECLAIM for the nine refinery-sector facilities, the same types of air pollution control equipment with similar impacts to the same environmental topic areas that were previously analyzed are expected to occur. However, since the proposed project will have an incremental increase in the number of new SCRs installed with the associated ammonia storage tanks and the number of existing SCRs upgraded, the impacts to air quality during construction and GHGs, hazards and hazardous materials associated with ammonia, and hydrology due to water demand will be more severe than the project analyzed in December 2015 Final PEA for NOx RECLAIM.

The proposed project is also expected to involve the replacement of existing burners with ULNBs and these activities were not previously analyzed in the December 2015 Final PEA for NOx RECLAIM. The installation of ULNBs are expected to contribute to additional construction air quality impacts and construction GHGs, which will contribute to increasing the severity of the construction air quality GHGs impacts previously analyzed in the December 2015 Final PEA for NOx RECLAIM. No other environmental topic areas will be impacted as activities associated with replacing existing burners with ULNBs.

Of the environmental topic areas previously analyzed in the December 2015 Final PEA for NOx RECLAIM which were concluded to have significant and unavoidable impacts and their applicability to the proposed project as identified in Table 1.5-1, the proposed project will result in an incremental increase in the number of new SCRs installed with the associated ammonia storage tanks and the number of existing SCRs upgraded, and replacements of existing burners with ULNBs.

Overall, the analysis of these incremental changes indicates that the type and extent of the physical activities that facility operators may undertake to comply with the BARCT requirements in PR 1109.1 are expected to be similar and will cause similar but more severe potentially significant secondary adverse environmental impacts for the same environmental topic areas. For this reason, the proposed project is expected to have significant effects that were previously examined in the December 2015 Final PEA for NOx RECLAIM but that will be substantially more severe [CEQA Guidelines Section 15162(a)(3)(B)].

As such, if proposed project is implemented significant and unavoidable adverse environmental impacts to the air quality during construction and GHGs, hazards and hazardous materials associated with ammonia, and hydrology due to water demand are expected to occur.

Potential Environmental Impacts Found Not To Be Significant

CEQA requires this section of the SEA to identify the environmental topic areas that were analyzed and concluded to have no impacts or less than significant impacts, if the proposed project is implemented. For the environmental topic areas identified as having no impacts, CEQA Guidelines Section 15128 requires the analysis to contain a statement briefly indicating the reasons that various effects of a project were determined not to have significant impacts and were therefore not discussed in detail.

This subchapter of the SEA is divided into two sections. The first section identifies the environmental topic areas that were previously concluded in the NOP/IS for the December 2015 Final PEA for NOx RECLAIM to have either less than significant impacts or no impacts (e.g., agriculture and forestry resources; biological resources; cultural and tribal cultural resources; geology and soils; land use and planning; mineral resources; noise; population and housing; public services; and recreation), and as such, were not analyzed further in the December 2015 Final PEA for NOx RECLAIM. This section also assesses whether these previously dismissed environmental topic areas in the December 2015 Final PEA for NOx RECLAIM would be affected by the proposed project, and explains why this SEA concludes that the proposed project would not change the previous conclusions reached in the December 2015 Final PEA for NOx RECLAIM for any of these environmental topic areas. Also, since the new environmental topic area of wildfires was added to the CEQA Guidelines after the December 2015 Final PEA for NOx RECLAIM was certified, this section analyzes whether the proposed project would cause any wildfire-associated impacts and explains why this SEA concludes that no impacts on wildfires would be expected to occur.

The second section identifies the environmental topic areas which were previously concluded in the December 2015 Final PEA for NOx RECLAIM to have less than significant impacts (e.g., aesthetics, air quality during operation, energy, water quality, solid and hazardous waste, and transportation and traffic). This section independently considers the currently proposed project and analyzes the incremental changes, if any, relative to the baseline, which is the project analyzed in the December 2015 Final PEA for NOx RECLAIM, in order to determine if the previous conclusions of less than significant impacts for the environmental topic areas of aesthetics, air quality during operation, energy, water quality, solid and hazardous waste, and transportation and traffic need to be changed. The section explains why this SEA concludes that the proposed project would not change the previous less than significant conclusions reached in the December 2015 Final PEA for NOx RECLAIM for aesthetics, air quality during operation, energy, water quality, solid and hazardous waste, and transportation and traffic.

Other CEQA Topics

CEQA documents are also required to consider and discuss the potential for growth-inducing impacts [CEQA Guidelines Section 15126(d)] and to explain and make findings about the project's relationship between short-term and long-term environmental goals [CEQA Guidelines Section 15065(a)(2)]. Additional analysis in chapter 4 confirms that the proposed project would not result in irreversible environmental changes or the irretrievable commitment of resources, foster economic or population growth, or the construction of additional housing. Further, implementation of the proposed project is not expected to achieve short-term goals to the disadvantage of long-term environmental goals.

Summary Chapter 5 - Alternatives

Since significant impacts are associated with the proposed project, CEQA Guidelines Section 15126(e) requires a CEQA document to consider and discuss alternatives to the proposed project. The following alternatives to the proposed project were identified and are summarized in Table 1.5-2: 1) Alternative A – No Project; 2) Alternative B – More Stringent Proposed Project; 3) Alternative C – Less Stringent Proposed Project; and 4) Alternative D – Limited Start-Up, Shutdown, Malfunction. Pursuant to the requirements in CEQA Guidelines Section 15126.6(b) to mitigate or avoid the significant effects that a project may have on the environment, Table 1.5-3 provides a comparison of individual requirements that comprise the proposed project and that have potentially significant adverse impacts, to each of the project alternatives. Potentially significant adverse impacts to the environmental topics of air quality during construction and GHGs, hazards and hazardous materials due to ammonia, and hydrology (water demand) were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. The proposed project may make these aforementioned impacts substantially more severe. However, the proposed project is not expected to create new potentially significant adverse impacts for other environmental topic areas. The proposed project is considered to provide the best balance between achieving requisite BARCT NOx emissions reductions and the secondary adverse environmental impacts that may occur due to activities associated with construction and operation of new or modified air pollution control equipment or combustion equipment, and the storage, use and transportation of ammonia (a hazardous material) associated with operating certain air pollution control equipment (e.g., SCRs and UltraCat™ with DGS) while achieving the overall objectives of the proposed project.

Table 1.5-2
Summary of the Proposed Project and Alternatives

Rule Elements	Proposed Project	Alternative A: No Project	Alternative B: More Stringent Proposed Project	Alternative C: Less Stringent Proposed Project	Alternative D: Limited Start-Up, Shutdown, Malfunction
BARCT NOx Limits	*Boilers:* 40 ppm (<40 MMBTU/hr)[a], 5 ppm (>40 MMBTU/hr) *Gas Turbines:* 2 ppm (natural gas), 3ppm (refinery fuel gas) *Ground Level Flares:* 20 ppm *FCCUs:* 2 ppm (over 365 days), 5 ppm (over 7 days) *Petroleum Coke Calciner:* 5 ppm (over 365 days) 10 ppm (over 7 days) *Process Heaters:* 40 ppm (<40 MMBTU/hr)[b], 5 ppm (> 40 MMBTU/hr) *SRU/TGUs:* 30 ppm *SMR Heaters:* 5 ppm *Sulfuric Acid Furnaces:* 30 ppm *Vapor Incinerators:* 30 ppm	The facilities would still be subject to AB617 which requires BARCT analysis and implementation of BARCT as soon as possible; thus, the limits would be the same as under the proposed project. However, instead of the command-and-control approach under the PR 1109.1 implementation schedule, the facilities would demonstrate compliance under the existing RECLAIM program which allows for RTCs, and according to the analysis conducted in the December 2015 Final PEA for NOx RECLAIM.	Same as Proposed Project	Same as Proposed Project	Same as Proposed Project
Potential NOx Emission Reductions	Approximately 7 to 8 tpd	2 tpd[c]	Same as Proposed Project	Same as Proposed Project	Same as Proposed Project
Heaters (< 40 MMBTU/hr) at 9 ppm NOx[b]	Compliance within 10 years from rule adoption	Indefinite. Timeline for demonstration of BARCT would occur according to the existing NOx RECLAIM program.	Compliance within 5 years from rule adoption	Same as Proposed Project	Same as Proposed Project
Boilers (<40 MMBTU/hr) at 5 ppm NOx[a]	Compliance within 6 months for 50% or more of burners cumulatively being replaced	Indefinite. Timeline for demonstration of BARCT would occur according to the existing NOx RECLAIM program.	Compliance within 6 months for 25% or more of burners cumulatively being replaced	Same as Proposed Project	Same as Proposed Project

Table 1.5-2 (concluded)
Summary of the Proposed Project and Alternatives

Rule Elements	Proposed Project	Alternative A: No Project	Alternative B: More Stringent Proposed Project	Alternative C: Less Stringent Proposed Project	Alternative D: Limited Start-Up, Shutdown, Malfunction
I-Plan	Option 1: 70% at Phase I, 100% at Phase II Option 2: 60% at Phase I, 80% at Phase II, 100% at Phase III Option 3: 50% at Phase I, 100% at Phase II Option 4: 50-60% at Phase I, 80% at Phase II 100% at Phase III Option 5: 50% at Phase I, 70% at Phase II 100% at Phase III	Indefinite. Timeline for demonstration of BARCT would occur according to the existing NOx RECLAIM program.	Same as Proposed Project	Option 1: 35% at Phase I, 50% at Phase II, 100% at Phase III Option 2: 30% at Phase I, 60% at Phase II, 100% at Phase III Option 3: 25% at Phase I, 50% at Phase II, 100% at Phase III Option 4: 30% at Phase I, 60% at Phase II 100% at Phase III Option 5: 25% at Phase I, 50% at Phase II 100% at Phase III	Same as Proposed Project
Start-Up, Shutdown and Malfunction Allowance	*Gas Turbines:* 2 hours *Boilers, Process Heaters, & SMR Heaters:* 48 hours *SMR with Gas Turbine:* 60 hours *FCCUs, Petroleum Coke Calciner, and SRU/TG Incinerators:* 120 hours	No allowances would be necessary because demonstration of BARCT would occur according to the existing NOx RECLAIM program.	Same as Proposed Project	Same as Proposed Project	*Gas Turbines:* 2 hours *Boilers, Process Heaters, & SMR Heaters:* 24 hours *SMR with Gas Turbine:* 30 hours *FCCUs, Petroleum Coke Calciner, and SRU/TG Incinerators:* 60 hours

a Boilers (<40 MMBTU/hr) are currently subject to a 40ppm NOx limit, but will be subject to a 5ppm NOx limit within 6 months of 50% of more of the burners cumulatively being replaced.
b Heaters (<40 MMBTU/hr) are currently subject to a 40ppm NOx limit, but will be subject to a 9ppm NOx limit within 10 years of rule adoption.
c Actual emission reductions under this alternative appear to be substantially less than the amount predicted in the 2015 RECLAIM amendment. See discussion in section 5.3.1.2 Alternative A – No Project.

Table 1.5-3
Comparison of Adverse Environmental Impacts of the Proposed Project and Alternatives

Environmental Topic Area	Proposed Project	Alternative A: No Project	Alternative B: More Stringent Proposed Project	Alternative C: Less Stringent Proposed Project	Alternative D: Limited Start-Up, Shutdown, Malfunction
Air Quality & GHGs	• Reduces total operational NOx emissions by approximately 7 to 8 tpd and annual PM2.5 concentration by ~~0.12~~ 0.11 μg/m3 without increasing CO emissions via air pollution control equipment at full implementation by 2034 • With mitigation, significant unavoidable increase in peak daily emissions for construction: VOC: ~~178~~ 155 lbs/day NOx: ~~873~~ 1,062 lbs/day CO: ~~4,941~~ 4,306 lbs/day SOx: ~~9~~ 8 lbs/day PM10: ~~128~~ 183 lbs/day PM2.5: ~~52~~ 60 lbs/day • Without mitigation, less-than-significant increase in peak daily emissions for operation: VOC: < 1 lb/day NOx: -13,980 lbs/day CO: 2 lbs/day SOx: < 1 lb/day PM10: < 1 lb/day PM2.5: < 1 lb/day • Without mitigation, less-than-significant increase in annual GHGs of ~~2,051~~ 2,029 MT/yr • Restricting the duration of SSM events will limit an unquantifiable amount of intermittent emissions of NOx that will occur when air pollution control equipment is offline • Sources of health risk are diesel particulate matter from construction and ammonia usage from operation. Health risk from short term construction (maximum 3 years) cannot be reliably quantified because cancer risk is calculated with 25, 30, or 70 year exposure rates. Operational use of ammonia will result in acute and chronic hazard indexes less than the threshold of 1.0. • Ammonia is limited to 5 ppm	• Reduced NOx allocations by 12 tpd NOx fulfilled primarily by surrender of RTCs, with full implementation by December 31, 2022 • In lieu of surrendering RTCs, NOx reduction projects could be conducted according to the December 2015 Final PEA for NOx RECLAIM. Peak day construction emissions, peak day operational emissions, and total GHGs would be the same as previously analyzed in the December 2015 Final PEA for NOx RECLAIM and the • Implementation of CMB-05 per the 2016 AQMP as analyzed in the March 2017 Final Program EIR for 2016 AQMP will continue to be required in accordance with BARCT • BARCT per AB 617 will continue to be required.	• Reduces total operational NOx emissions by approximately 7 to 8 tpd and annual PM2.5 concentration by ~~0.12~~ 0.11 μg/m3 without increasing CO emissions via air pollution control equipment at full implementation by 2034, but with 0.37 tpd of NOx emission reductions from boilers and heaters < 40 MMBTU/hr achieved sooner than proposed project. • Peak day construction emissions, peak day operational emissions, and total GHGs are expected to be the same as the proposed project.	• Reduces total operational NOx emissions by approximately 7 to 8 tpd and annual PM2.5 concentration by ~~0.12~~ 0.11 μg/m3 without increasing CO emissions via air pollution control equipment at full implementation by 2034, but with fewer incremental NOx emission reductions occurring early in Phases I and II for each I-Plan option, but with 100% of the NOx emission reductions being achieved by Phase III. • Peak day construction emissions, peak day operational emissions, and total GHGs are expected to be the same as the proposed project.	• Reduces total operational NOx emissions by approximately 7 to 8 tpd and annual PM2.5 concentration by ~~0.12~~ 0.11 μg/m3 without increasing CO emissions via air pollution control equipment at full implementation by 2034 • Peak day construction emissions, peak day operational emissions, and total GHGs are expected to be the same as the proposed project. • Reducing the time allowed for SSM events by 50% for the same equipment categories as the proposed project, except for gas turbines, will further limit an unquantifiable amount of NOx emissions by 50% when air pollution control equipment is offline.

Table 1.5-3 (continued)
Comparison of Adverse Environmental Impacts of the Proposed Project and Alternatives

Environmental Topic Area	Proposed Project	Alternative A: No Project	Alternative B: More Stringent Proposed Project	Alternative C: Less Stringent Proposed Project	Alternative D: Limited Start-Up, Shutdown, Malfunction
Air Quality & GHG Impacts Significant?	• **Significant and unavoidable air quality impacts from construction** for VOC, NOx, and CO for PR 1109.1. The December 2015 Final PEA for NOx RECLAIM also concluded significant and unavoidable air quality construction impacts, and the proposed project increases the severity of the previous analysis. • **Less than significant air quality impacts from operation** for PR 1109.1. The project also achieves a net NOx emission reduction by approximately 7 to 8 tpd. The December 2015 Final PEA for NOx RECLAIM also concluded less than significant air quality operation impacts, and the proposed project increases the severity of the previous analysis while not changing the significance conclusion. • While calculations show less than significant GHG emissions for PR 1109.1, the December 2015 Final PEA for NOx RECLAIM concluded significant unavoidable GHG impacts; therefore, **significant and unavoidable GHG impacts** are expected with this proposed project. • **Less than significant health risk impact** for PR 1109.1. The December 2015 Final PEA for NOx RECLAIM also concluded less than significant health risk impact. • **Less than significant odor nuisance impact** for PR 1109.1. The December 2015 Final PEA for NOx RECLAIM also concluded less than significant odor nuisance impact.	• The December 2015 Final PEA for NOx RECLAIM concluded significant and unavoidable construction impacts for air quality, less than significant operational impacts, and significant unavoidable impacts for GHGs.	• The overall conclusions for construction and operation impacts are the same as the proposed project even though the portion of NOx emission reductions from boilers and heaters < 40 MMBTU/hr will be achieved sooner than proposed project.	• The overall conclusions for construction and operation impacts are the same as the proposed project, even with fewer incremental NOx emission reductions occurring early in Phases I and II for each I-Plan option, but with 100% of the NOx emission reductions being achieved by Phase III.	• The overall conclusions for construction and operation impacts are the same as the proposed project even though intermittent emissions of NOx occurring during SSM events are expected to be less than the proposed project

Table 1.5-3 (continued)
Comparison of Adverse Environmental Impacts of the Proposed Project and Alternatives

Environmental Topic Area	Proposed Project	Alternative A: No Project	Alternative B: More Stringent Proposed Project	Alternative C: Less Stringent Proposed Project	Alternative D: Limited Start-Up, Shutdown, Malfunction
Hazards & Hazardous Materials	• Increased use of approximately ~~4~~ 5 tons/day of NH3 used during operation.	• NOx reduction projects would be conducted according to the December 2015 Final PEA for NOx RECLAIM. Ammonia usage would be the same as previously analyzed in the December 2015 Final PEA for NOx RECLAIM.	• Same as proposed project	• Same as proposed project	• Same as proposed project
Hazards & Hazardous Materials Impacts Significant?	• **Significant** impacts for routine transportation, storage, and use of ammonia for PR 1109.1. The December 2015 Final PEA for NOx RECLAIM also concluded significant ammonia impacts, and the proposed project increases the severity of the previous analysis due to more installations and operation of SCR and SCR upgrades.	• The significance conclusions of the No Project Alternative would rely on those for the December 2015 Final PEA for NOx RECLAIM. • Significant impact for routine transportation, storage, and use of ammonia	• Same as proposed project	• Same as proposed project	• Same as proposed project

Table 1.5-3 (concluded)
Comparison of Adverse Environmental Impacts of the Proposed Project and Alternatives

Environmental Topic Area	Proposed Project	Alternative A: No Project	Alternative B: More Stringent Proposed Project	Alternative C: Less Stringent Proposed Project	Alternative D: Limited Start-Up, Shutdown, Malfunction
Hydrology	• Increased use of water for fugitive dust suppression during construction by ~~1,658~~ 1,961 gal/day • Increased use of water for hydrotesting by ~~220,000~~ 286,000 gal/day • No increased water use for operating air pollution control equipment	• NOx reduction projects would be conducted according to the December 2015 Final PEA for NOx RECLAIM. Water demand would be the same as previously analyzed in the December 2015 Final PEA for NOx RECLAIM.	• Same as proposed project unless the tightened schedule causes more construction projects occurring on a given day	• Same as proposed project or less amount of water for fugitive dust suppression on a peak day • Same as proposed project or less amount of water for hydrotesting on a peak day • Same as proposed project for operating air pollution control devices	• Same as proposed project
Hydrology Impacts Significant?	• Less than significant water demand impacts fugitive dust suppression during construction • Significant water demand impacts during hydrotesting: While the calculations show less than significant water demand impacts for hydrotesting for PR 1109.1, both the December 2015 Final PEA for NOx RECLAIM concluded significant water demand impacts for hydrotesting • Significant water use for operating air pollution control equipment: While the calculations show no increase in water use for operating air pollution control equipment for PR 1109.1, both the December 2015 Final PEA for NOx RECLAIM concluded significant operational water demand impacts due to the potential operation of a wet gas scrubber	The following conclusions for hydrology are from the December 2015 Final PEA for NOx RECLAIM: • Less than significant for water demand during construction • Significant for water demand during hydrotesting (assuming entire demand is based on potable water)	• Same as proposed project	• Same as proposed project, even if there are fewer overlapping projects using water for fugitive dust suppression and hydrotesting on peak day	• Same as proposed project

Summary Chapter 6 - References

This chapter contains a list of the references, and the organizations and persons consulted for the preparation of this SEA.

Summary Chapter 7 - Acronyms

This chapter contains a list of the acronyms that were used throughout the SEA and the corresponding definitions.

Appendix A

This appendix contains the latest versions of PRs 1109.1 and 429.1, PARs 1304 and 2005 and proposed rescinded Rule 1109 as follows:

Appendix A1: Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations

Appendix A2: Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations

Appendix A3: Proposed Amended Rule 1304 – Exemptions

Appendix A4: Proposed Amended Rule 2005 – New Source Review for RECLAIM

Appendix A5: Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries

Appendix B: CalEEMod® Files

This appendix contains the CalEEMod Files for construction and mobile source operational activities associated with each type of method for reducing NOx emissions to BARCT levels.

Appendix C: CEQA Impact Calculations

This appendix contains a summary of total construction emissions, a summary of total operational impacts, and operational impacts per facility. The water demand impacts associated with construction are included in this appendix as well.

Appendix D: List of Affected Facilities and Equipment

This appendix contains the list of facilities and equipment that will be subject to the proposed project.

Appendix E: Off-site Consequence, Ammonia Slip, and PM2.5 Concentration Analyses

This appendix contains analysis of the off-site consequence from ammonia, and calculations for ammonia slip and PM2.5 that could result from implementing the proposed project.

Appendix F: Comment Letters Received on the Draft SEA and Responses to Comments

This appendix contains the comment letters received on the Draft SEA. Comment letters were sectioned with brackets, and a response was provided for each section of each comment letter.

CHAPTER 2

PROJECT DESCRIPTION

2.1 PROJECT LOCATION

The South Coast AQMD has jurisdiction over an area of approximately 10,743 square miles, consisting of the four-county South Coast Air Basin (Basin), the Riverside County portion of the Salton Sea Air Basin (SSAB) and the non-Palo Verde, Riverside County portion of the Mojave Desert Air Basin (MDAB). The Basin, a subarea of South Coast AQMD's jurisdiction, is bounded by the Pacific Ocean to the west, the San Gabriel, San Bernardino, and San Jacinto mountains to the north and east and includes all of Orange County and the non-desert portions of Los Angeles, Riverside, and San Bernardino counties. The Riverside County portion of the SSAB is bounded by the San Jacinto Mountains in the west and spans eastward up to the Palo Verde Valley. A federal non-attainment area (known as the Coachella Valley Planning Area) is a subregion of Riverside County and the SSAB that is bounded by the San Jacinto Mountains to the west and the eastern boundary of the Coachella Valley to the east (see Figure 2.1-1). All facilities affected by the proposed project are located in the Los Angeles County portion of the South Coast AQMD's jurisdiction.

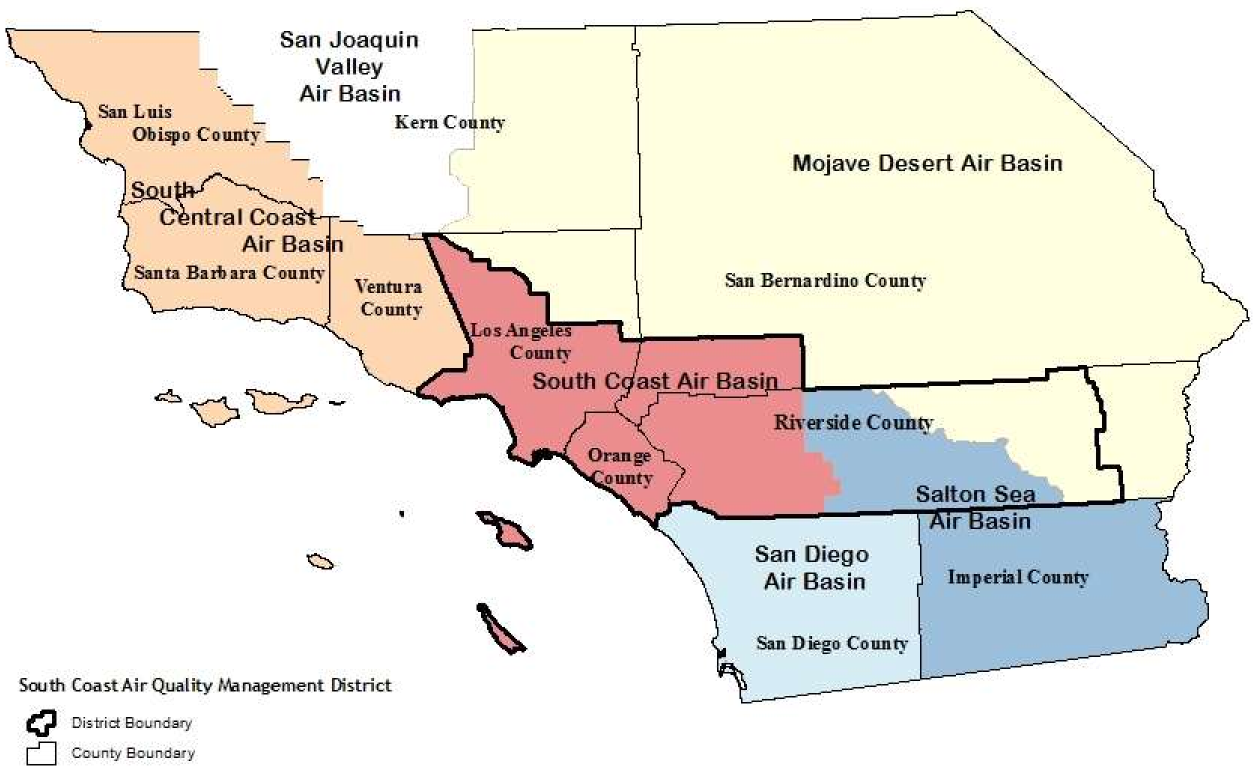


Figure 2.1-1
Southern California Air Basins and South Coast AQMD's Jurisdiction

2.2 PROJECT BACKGROUND

Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries was adopted in 1985, and subsequently amended in 1988. Rule 1109 established a refinery-wide NOx emission limit of 0.14 pound per million British thermal units (lb/MMBTU) (approximately 120 ppmv NOx corrected to three percent oxygen) for boilers and process heaters operated on gaseous fuel, 0.308 lb/MMBTU (approximately 250 ppmv NOx corrected to three percent oxygen) for units operated on liquid fuel, and a weighted average of these limits for units operated concurrently on both liquid and gaseous fuels. After Regulation XX – Regional Clean Air Incentives Market (RECLAIM) was adopted in 1993, petroleum refineries and facilities with operations related to petroleum facilities transitioned from complying with Rule 1109 to the market-based RECLAIM program. Instead of setting specific limits on each piece of equipment and each process that contributes to air pollution as is stipulated by traditional 'command-and-control' regulations, under the RECLAIM program each facility has a NOx and/or SOx annual emissions limit (allocation) and facility operators are provided the flexibility to decide what equipment, processes, and materials they will use to maintain or reduce emissions to levels less than their annual emission allocations. In lieu of reducing emissions, facility owners or operators are provided the option to access the trading market to purchase RECLAIM Trading Credits (RTCs) from other facilities that have achieved emission reductions to less than their annual allocation. The portion of Regulation XX that focuses on reducing NOx emissions is referred to as "NOx RECLAIM" while the portion that focuses on reducing SOx emissions is referred to as "SOx RECLAIM."

At the onset of the NOx RECLAIM program, each facility participating in the program was issued NOx annual allocations, which declined annually from 1993 until 2003, and remained constant thereafter. The annual allocations issued to facilities reflect the Best Available Retrofit Control Technology (BARCT) analysis conducted at the time. California Health and Safety Code Section 40440 and 39616 require a BARCT reassessment of the advancements made in air pollution control technologies to ensure that RECLAIM facilities achieve the same emission reductions that would have otherwise occurred under a command-and-control approach, and that emission reductions from the RECLAIM program continue to contribute to the efforts in the Basin to achieve the federal National Ambient Air Quality Standards. The South Coast AQMD conducted BARCT reassessments for the NOx RECLAIM program in 2005 and 2015.

The NOx RECLAIM program started in 1993 with a universe of 392 facilities. Over time, the number of participants reduced to 304 facilities at the end of the 2005 compliance year, 276 facilities at the end of compliance year 2011, and 275 facilities at the end of compliance year 2013. The reduction in the number of facilities participating in the NOx RECLAIM program since inception has been primarily due to facility shutdowns and/or consolidations. As of the end of the 2017 compliance year, there were 262 facilities in NOx RECLAIM which are responsible for 19.9 tons per day of NOx emissions.

Based on the BARCT evaluation conducted in January 2005, amendments were made to the NOx RECLAIM program that resulted in a reduction of RTCs across the board by 7.7 tons per day. The RTCs were further reduced from compliance years 2007 to 2011, and the total RTCs in the NOx RECLAIM universe allocated for compliance year 2011 amounted to 26.5 tons per day. However, the audited emissions in compliance year 2011 were 20.01 tons per day, equating to 6.49 tons per day of excess holdings.

In 2015, South Coast AQMD staff conducted a BARCT analysis for the 275 NOx RECLAIM facilities which indicated that: 1) 21 out of the 30 electric generating facilities (EGFs) were confirmed to operate at current BARCT or BACT levels; 2) 224 non-power plant facilities (plus the remaining nine EGFs for a total 233 facilities) either had no new BARCT identified or the installation of air pollution control equipment was not cost-effective; and 3) 21 facilities were identified for further emission reductions to BARCT levels.

Recognizing that many of the RECLAIM program's original advantages were diminishing, South Coast AQMD staff developed the 2016 AQMP to include Control Measure CMB-05 – Further NOx Reductions from RECLAIM Assessment, which committed to achieve BARCT level equivalency for all facilities through a command-and-control regulatory structure while alleviating facilities from installing a technology that could quickly become obsolete or only serve as an intermediate technology. Also, the South Coast AQMD Governing Board directed staff to implement an orderly sunset of the RECLAIM program by transitioning equipment at NOx RECLAIM facilities from a facility permit structure to an equipment-based command-and-control regulatory structure per South Coast AQMD Regulation XI – Source Specific Standards in order to achieve an additional five tons per day of NOx emission reductions by 2025. Thus, CMB-05 committed to a process of transitioning NOx RECLAIM facilities to a command-and-control regulatory structure and to ensure that the applicable equipment will meet BARCT level equivalency as soon as practicable.[1]

In July 2017, California State Assembly Bill 617 – Nonvehicular Air Pollution: Criteria Air Pollutants and Toxic Air Contaminants (AB 617) was approved by the Governor, which addresses nonvehicular air pollution from sources including NOx RECLAIM facilities that are in the state's greenhouse gas cap-and-trade program in accordance with the requirements of AB 617. Among the requirements in AB 617 is for air districts to implement BARCT no later than December 31, 2023, by prioritizing permitted units that have not modified emissions-related permit conditions for the greatest period of time.

In accordance with CMB-05 and AB 617, to date, several rules have been amended in accordance with the Governing Board's direction. Currently, South Coast AQMD staff is continuing this transition process by developing the proposed project which is comprised of Proposed Rules (PRs) 1109.1 and 429.1, Proposed Amended Rules (PARs) 1304 and 2005, and proposed rescinded Rule 1109.

PR 1109.1 proposes to establish BARCT requirements to reduce NOx emissions while not increasing CO emissions from petroleum refineries and facilities with operations related to petroleum refineries which includes asphalt plants, biofuel plants, hydrogen production plants, facilities that operate petroleum coke calciners, sulfuric acid plants, and sulfur recovery plants. The following combustion equipment categories will be applicable to PR 1109.1: 1) boilers; 2) flares; 3) fluidized catalytic cracking units; 4) gas turbines; 5) petroleum coke calciners; 6) process heaters; 7) steam methane reformer (SMR) heaters; 8) SMR heaters with gas turbine; 9) sulfur recover units/tail gas treating units (SRU/TG); 10) sulfuric acid furnaces; and 11) vapor incinerators. PR 1109.1 will transition affected equipment operating at 16 facilities, including nine petroleum refineries, three small refineries, and four facilities with related operations, that are subject to transition from the NOx RECLAIM program to a command-and-control regulatory

[1] South Coast AQMD, Final 2016 Air Quality Management Plan, Chapter 4 – Control Strategy and Implementation, pp. 4-15, March 2017. https://www.aqmd.gov/home/air-quality/clean-air-plans/air-quality-mgt-plan/final-2016-aqmp

structure. A list of affected facilities and equipment is provided in Appendix D of this Final ~~Draft~~ SEA.

During development of PR 1109.1, the issue of startup and shutdown events was identified as a concern. When a unit or its associated air pollution control equipment starts or ceases operating, or the equipment is not operating at steady-state conditions, emission spikes could potentially cause exceedances of NOx and CO emission limits during these intervals. To address this issue, PR 429.1 proposes new requirements for startup, shutdown, and certain maintenance events, including an exemption from the NOx and CO emission limits in PR 1109.1 during these events. PR 429.1 also proposes notification and recordkeeping requirements for units that will be subject to PR 1109.1.

To achieve the BARCT NOx concentration limits under PR 1109.1, installations or modifications of post-combustion air pollution control equipment such as SCR and ULNBs is expected to occur. This equipment will reduce NOx emissions but may also increase emissions of particulate matter and SOx, which may trigger BACT and require sulfur clean-up of the refinery fuel gas. PAR 1304 and PAR 2005 propose to include a narrow BACT exemption to address these potential emission increases associated with installation of new or the modification of existing post-combustion air pollution control equipment, or other equipment modifications to comply with the proposed NOx emission limits in PR 1109.1. Because the proposed adoption of PR 1109.1 will make Rule 1109 outdated and no longer necessary, Rule 1109 is proposed to be rescinded.

Implementation of the proposed project is estimated to reduce NOx emissions by approximately seven to eight tons per day after implementation of BARCT limits in PR 1109.1, and is expected to be achieved by retrofitting existing equipment with a variety of air pollution control equipment (e.g., SCR technology/systems, ULNB, LoTOx™ with WGS, and UltraCat™ with DGS).

While reducing emissions of NOx and other contaminants will create an environmental benefit, activities that facility operators may undertake to implement the proposed project may also create secondary potentially significant adverse environmental impacts to air quality during construction and greenhouse gases, hazards and hazardous materials during ammonia transportation, storage, and use, and hydrology due to water demand.

The proposed project is estimated to reduce NOx emissions by approximately seven to eight tons per day and regional $PM_{2.5}$ emissions by ~~0.12~~ 0.11 $\mu g/m^3$, while not increasing CO emissions.

2.3 PROJECT OBJECTIVES

The main objectives of the proposed project are to: 1) reduce NOx emissions from refinery equipment and transition equipment that is currently permitted under the NOx RECLAIM program to a command-and-control regulatory structure; 2) implement Control Measure CMB-05 by requiring affected equipment operating at RECLAIM or former RECLAIM facilities to comply with current BARCT in accordance with an implementation schedule for transitioning affected units at NOx RECLAIM facilities to a command-and-control regulatory structure; and 3) comply with the BARCT requirements in accordance with AB 617.

2.4 PROJECT DESCRIPTION

The proposed project consists of PRs 1109.1 and 429.1, PARs 1304 and 2005, and the proposed rescission of Rule 1109. PR 1109.1 is being proposed to facilitate the transition of petroleum refineries and facilities with related operations to petroleum refineries from a market-based program to an equipment-based command-and-control regulatory structure, thus implementing Control Measure CMB-05 of the 2016 AQMP and AB 617. PR 1109.1 applies to any owner or operator of units at petroleum refineries and facilities with related operations to petroleum refineries, which includes asphalt plants, biofuel plants, hydrogen production plants, petroleum coke calcining facilities, sulfuric acid plants, and sulfur recovery plants. PR 1109.1 will update NOx emission limits to reflect current NOx BARCT, is estimated to reduce NOx emissions by approximately seven to eight tons per day without increasing CO emissions, and decrease PM2.5 concentrations regionwide by ~~0.12~~ 0.11 µg/m^3 on an annual average. Additionally, PR 1109.1 outlines multiple compliance schedules; establishes provisions for monitoring, recordkeeping, and reporting; and sets exemptions from specific provisions. PR 1109.1 applies to 16 out of the 262 facilities currently in the NOx RECLAIM program which are responsible for 12.3 out of 19.9 tons per day of the NOx emissions based on the 2017 RECLAIM Annual Emission Reports.

PR 429.1 provides exemptions for the NOx and CO limits during the period when the unit is starting up, shutting down, and during commissioning and certain ~~catalyst~~ maintenance activities, and PARs 1304 and 2005 provide a narrow BACT exemption ~~from NSR~~ for co-pollutant issues associated with installation of SCR systems or installation of new units with SCR. PR 429.1, and PARs 1304 and 2005 do not require any additional emission controls. Because the proposed adoption of PR 1109.1 will make Rule 1109 outdated and no longer necessary, Rule 1109 is proposed to be rescinded.

Appendix A of the~~is~~ Draft SEA contained~~s~~ a copy of preliminary draft versions of PRs 1109.1 (version dated August 20, 2021) and 429.1 (version dated August 18, 2021), PARs 1304 (version dated August 17, 2021) and 2005 (version dated August 17, 2021), and proposed rescinded Rule 1109 (version dated August 17, 2021). After the release of the Draft SEA for public review and comment on September 3, 2021 for a 46-day public review and comment period which ended on October 19, 2021, PRs 1109.1 and 429.1, and PAR 1304 were updated.

Summary of PR 1109.1

PR 1109.1 was reorganized for clarity. To avoid confusion, the summary of PR 1109.1 included in the Draft SEA has been presented in ~~strikeout text~~ and completely replaced in this Final SEA with the latest version, shown in underlined text, as follows.

Subdivision (a) – Purpose

The purpose of this rule is to reduce emissions of NOx, while not increasing CO emissions, from combustion equipment at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries. As discussed in Chapter 1, PR 1109.1 is needed to transition Petroleum Refineries and Facilities With Related Operations to Petroleum Refineries from RECLAIM to a command-and-control regulatory structure. PR 1109.1 is a command-and-control rule that is designed to satisfy requirements to establish BARCT under Health and Safety Code Section 40920.6 which implements AB 617.

Subdivision (b) – Applicability

PR 1109.1 applies to combustion equipment at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries, including Asphalt Plants, Biofuel Plants, Hydrogen Production Plants, Petroleum Refineries, facilities that operate Petroleum Coke Calciners, Sulfuric Acid Plants, and Sulfur Recovery Plants. The provisions of PR 1109.1 apply to Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries while in RECLAIM and after they transition out of RECLAIM. Combustion equipment which are subject to this rule are categorized as Boilers, Flares, Fluid Catalytic Cracking Units, Gas Turbines, Petroleum Coke Calciners, Process Heaters, Steam Methane Reformer Heaters, Sulfuric Acid Furnaces, Sulfur Recovery Units/Tail Gas Incinerators, and Vapor Incinerators.

Subdivision (c) – Definitions

Definitions in PR 1109.1 are incorporated to define equipment, fuels, and other rule terms. Below are some key definitions that are used in PR 1109.1. To provide clarity, definitions are used in the proposed rule and this staff report as a proper noun to better distinguish defined terms from common terms. Refer to PR 1109.1 for a complete list of definitions.

PR 1109.1 includes a definition for "Facilities With The Same Ownership" which is used in a couple of key provisions for alternative compliance plans and certain provisions for interim emission limits.

- FACILITIES WITH THE SAME OWNERSHIP means Facilities and their subsidiaries, Facilities that share the same board of directors, or Facilities that share the same parent corporation.

At the time of this staff report, the following are the PR 1109.1 Facilities With The Same Ownership:

Table 2.4-1: Facilities With The Same Ownership

Owner	Facility	Facility ID
Marathon Petroleum Company/Tesoro Refining and Marketing, LLC (Marathon)	Tesoro – Carson	174655
	Tesoro – Wilmington	800436
	Tesoro – Sulfur Recovery Plant	151798
	Tesoro – Petroleum Coke Calciner	174591
Phillips 66	Phillips 66 – Carson	171109
	Phillips 66 – Wilmington	171107
Valero	Ultramar/Valero Wilmington	800026
	Valero Asphalt Plant	800393

The definition of "Unit" was included to streamline the rule language.

- UNIT means, for the purpose of this rule, any Boilers, Flares, FCCUs, Gas Turbines, Petroleum Coke Calciners, Process Heaters, SMR Heaters, Sulfuric Acid Furnaces, SRU/TG Incinerators, or Vapor Incinerators that requires a South Coast AQMD permit and is not required to comply with a NOx concentration limit in another South Coast AQMD Regulation XI rule.

Subdivision (d) – Concentration Limits

This subdivision establishes the proposed BARCT NOx Concentration Limits and Corresponding CO Concentration Limits for combustion equipment at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries. PR 1109.1 Table 1 lists the NOx Concentration Limits and Corresponding CO Concentration Limits for each class and category of equipment subject to PR 1109.1 and identifies the corresponding rolling averaging time and percent of oxygen as the basis for emissions measurement or calculation. Averaging times must be calculated as established in Attachment A of PR 1109.1 for any unit that operates with CEMS. All averaging times based on CEMS are rolling averages and are established for different types of equipment in Table 1 and Table 2 of PR 1109.1. Units that must demonstrate compliance with a source test are required to demonstrate compliance based on the time specified in the approved source test protocol as discussed in subdivision (l). Subdivision (f) lays out the compliance dates for a Facility complying with the NOx and CO Concentration Limits in Table 1.

NOx CONCENTRATION LIMIT(S) means the NOx concentration limit at the applicable percent O_2 correction and averaging period specified in Table 1, Table 2, Table 3, or Table 5 – Maximum Alternative BARCT NOx Concentration Limits for a B-Cap (Table 5).

CORRESPONDING CO CONCENTRATION LIMIT(S) means the CO concentration limit, that corresponds to the referenced NOx Concentration Limit, at the applicable percent O_2correction and averaging period specified in Table 1, Table 2, or Table 3 – Interim NOx and CO Concentration Limits (Table 3).

Table 2.4-2: PR 1109.1 Table 1 – NOx and CO Concentration Limits

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers <40 MMBtu/hour	Pursuant to subparagraphs (d)(2)(A) and (d)(2)(B)	400	3	24-hour
Boilers ≥40 MMBtu/hour	5	400	3	24-hour
FCCU	2	500	3	365-day
	5			7-day
Flares	20	400	3	2-hour
Gas Turbines fueled with Natural Gas	2	130	15	24-hour
Gas Turbines fueled with Gaseous Fuel other than Natural Gas	3	130	15	24-hour
Petroleum Coke Calciner	5	2,000	3	365-day
	10			7-day
Process Heaters <40 MMBtu/hour	Pursuant to subparagraphs (d)(2)(A) and (d)(2)(C)	400	3	24-hour
Process Heaters ≥40 MMBtu/hour	5	400	3	24-hour
SMR Heaters	5	400	3	24-hour
SMR Heaters with Gas Turbine	5	130	15	24-hour
SRU/TG Incinerators	30	400	3	24-hour
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	30	400	3	24-hour

[1] Averaging times apply to Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule; compliance for Units without a certified CEMS shall be demonstrated pursuant to paragraph (l)(1).

Proposed NOx Limits for Boilers and Process Heaters with a Rated Heat Input Capacity Less than 40 MMBtu/hr – Paragraph (d)(2)

PR 1109.1 establishes NOx Concentration Limits for Boilers and Process Heaters less than 40 MMBtu/hr in two steps. The averaging time, oxygen correction, and Corresponding CO Concentration Limit are specified in Table 1 and is the same for the applicable NOx Concentration Limits to these Units in both steps. The compliance schedule for the two steps is addressed under the Compliance Schedule in Table 4. The NOx Concentration Limit for Boilers and Process Heaters less than 40 MMBtu/hr is:

- First Step: 40 ppmv for both Boilers and Process Heaters; then
- Second Step: 5 ppmv for Boilers and 9 ppmv for Process Heaters.

Conditional NOx Concentration Limits - Paragraph (d)(3)

PR 1109.1 provides alternative BARCT NOx limits for units which are currently operating at or below NOx Concentration Limits in Table 2 of PR 1109.1, shown as Table 3-3 below. This provision is designed to recognize that some units have existing pollution controls that are currently operating near the NOx Concentration Limits in PR 1109.1 Table 1, and it is not cost-effective to require replacement or installation of additional pollution controls for those Units. PR 1109.1 includes conditions that an owner or operator must meet if an owner or operator elects to meet the Conditional NOx Concentration Limits and Corresponding CO Concentration Limits in Table 2, in lieu of the NOx Concentration Limits and Corresponding CO Concentration Limits in Table 1.

Table 2.4-3: PR 1109.1 Table 2 – Conditional NOx and CO Concentration Limits

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers ≥110 MMBtu/hour	7.5	400	3	24-hour
FCCUs	8	500	3	365-day
	16			7-day
Gas Turbines fueled with Natural Gas	2.5	130	15	24-hour
Process Heaters ≥40 – ≤110 MMBtu/hour	18	400	3	24-hour
Process Heaters >110 MMBtu/hour	22	400	3	24-hour
SMR Heaters	7.5	400	3	24-hour
Vapor Incinerators	40	400	3	2-hour

1 Averaging times apply to Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule; compliance for Units without a certified CEMS shall be demonstrated pursuant to paragraph (l)(1).

PR 1109.1 allows owners or operators to use PR 1109.1 Table 2 Conditional NOx Concentration Limits in lieu of meeting Table 1 NOx Concentration Limits. The owner or operator must meet all of the conditions specified under paragraph (d)(3) and meet the permit submittal and compliance dates under paragraph (f)(3), including submitting a permit application by June 1, 2022.

Conditions for Using Conditional NOx Concentration Limits

Since the Table 2 NOx Concentration Limits can be used in lieu of Table 1 NOx Concentration Limits to establish the Facility BARCT Emission Target under the alternative BARCT compliance plans, staff realized it was critical to establish conditions to ensure only those Units that were operating near the NOx Concentration Limits in Table 1 and would have high cost-effectiveness values to meet NOx Concentration Limits in Table 1 are allowed to use the Conditional NOx Concentration Limits. Staff was also concerned that owners or operators could potentially install pollution controls and meet the Conditional NOx Concentration Limits instead of the more stringent Table 1 NOx limits and could create a "budget" of NOx emissions that could be used to have higher NOx concentration levels for other Units.

Under subparagraph (d)(3)(A), the first condition for a unit to be allowed a Table 2 conditional limit is that the Executive Officer has not issued a Permit to Construct on or after December 4, 2015 for the installation of a pollution control device. This condition is to prevent Units with currently installed pollution control devices, such as SCR, which can achieve the Table 1 NOx Concentration Limits, from electing to comply with Table 2 conditional limits. December 4, 2015 was selected as this is the date when Regulation XX – RECLAIM was amended to reduce or shave allocations. The analysis was based on a technical analysis that large boilers and heaters could achieve a NOx concentration of 2 ppmv. Staff believes that Units modified after this date should have been designed to achieve the proposed NOx limits in Table 1. Boilers and heaters greater than or equal to 40 MMBtu/hour installed with a modern SCR can achieve 5 ppmv NOx, if not lower. This condition will also ensure Units that can achieve significant NOx reductions in a cost-effective manner, are required to meet the NOx and CO Concentration Limits under Table 1 of PR 1109.1.

The next two conditions, subparagraphs (d)(3)(B) and (d)(3)(C), are that emission reduction projects for Process Heaters greater than or equal to 40 MMBtu/hour but less than or equal to 110 MMBtu/hour cannot have an emission reduction potential (referred to in the rule as "Unit Reductions" and calculated pursuant to Attachment B in the rule) of 10 tons per year or more, and emission reduction projects for Boilers or Process Heaters greater than 110 cannot have an emission reduction potential of 20 tons per year or more. The potential emission reductions are based on the difference of the baseline emissions and the Table 1 concentration limits, scaled to the baseline emissions.

The next two conditions, subparagraphs (d)(3)(D) and (d)(3)(E), are that the Unit must not have an existing permit limit at or below the Table 1 NOx Concentration Limits or have a Representative NOx Concentration that is at or below the Table 1 NOx Concentration Limits. These conditions will prevent Units that are achieving NOx emissions that meet the Table 1 NOx Concentration Limits from electing to comply with the conditional limits.

FACILITY BARCT EMISSION TARGET means the total mass emissions per facility calculated based on the applicable Table 1 NOx emission limits or Table 2 conditional NOx limits and the 2017 annual NOx emissions, or another representative year as approved by the Executive Officer.

The last condition, subparagraph (d)(3)(F), excludes any unit that has been decommissioned pursuant to paragraph (f)(10) from being eligible to use the conditional NOx limits in Table 2.

Gas Turbines – Paragraph (d)(4)

PR 1109.1 provides an alternative NOx concentration limit of 5 ppmv (corrected to 15 percent oxygen on a dry basis) based on a 24-hour rolling average, instead of the 2-ppmv and 3-ppmv NOx limits for Gas Turbines operating on natural gas and refinery gas, respectively, during natural gas curtailment periods. Natural gas curtailment occurs when there is a shortage in the supply of pipeline Natural Gas due to limitations in the supply or restrictions in the distribution pipelines by the utility that supplies Natural Gas. A shortage in Natural Gas supply that is due to changes in the price of Natural Gas does not qualify as a Natural Gas curtailment. Corresponding CO Concentration Limits for the Gas Turbines subject to this provision are the same as listed in Table 1 and Table 2 of PR 1109.1.

Units With Combined Stacks – Paragraph (d)(5)

Paragraph (d)(5) requires Units With Combined Stacks to meet the most stringent applicable Table 1 or Table 2 NOx Concentration Limit. Below are the criteria to determine which requirements apply to Units With Combined Stacks if one or more of the Units fall in a different size category as follows:

- If multiple Units are combined:
  - One Unit is >110 MMBtu/hr and the other are less → >110 MMBtu/hr
  - All Units are ≥40 – 110 MMBtu/hr → ≥40 – ≤110 MMBtu/hr
  - One Unit is ≥40 MMBtu/hr and the other Units are less → ≥40 – ≤110 MMBtu/hr

CO Concentration Limits – Paragraph (d)(6)

PR 1109.1 Table 1 and Table 2 establish CO concentration limits for each class and category of equipment. As discussed, the purpose of this rule is to reduce emissions of NOx from combustion equipment at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries, with no increase in the associated CO emissions. The CO emissions for the classes and categories of equipment listed in PR 1109.1 Table 1 and Table 2 are generally representative of CO concentration limits in permits and consistent with other rules regulating similar combustion equipment. This paragraph allows an owner or operator of a Unit that has a CO concentration limit established in a Permit to Operate or Permit Construct before the date of rule adoption, to meet the CO concentration limit in the Permit to Operate or Permit to Construct in lieu of the applicable Corresponding CO Concentration Limit. The CO permit limit can include an actual permit limit or a reference to South Coast AQMD Rule 407 – Liquid and Gaseous Air Contaminants.

An owner or operator with six or more units, have the option to use a B-Plan or B-Cap that will allow the selection of a NOx limit that may be higher than the NOx limits established in PR 1109.1. However, regardless of the NOx limit selected in a B-Plan or B-Cap, the owner or operator is required to meet the applicable CO concentration limit in Table 1 or Table 2, or as allowed under paragraph (d)(6).

Subdivision (e) – Interim Concentration Limits

As discussed in Chapter 2, Interim NOx Concentration Limits are needed after Facilities transition out of RECLAIM and before the Unit meets the NOx limits in PR 1109.1 to ensure there is no backsliding and interference with attainment.

Interim NOx Concentration Limits (e)(1)

The interim NOx Concentration Limits in of PR 1109.1 applies to Facilities that elect to meet the Table 1 or Table 2 NOx Concentration Limits directly, all Units at a Facility that is complying with a B-Plan, and any Boiler or Process Heater less than 40 MMBtu/hour not included in a B-Cap. The approach for the interim Concentration Limits is different for owners or operators that select to comply with a B-Plan versus complying with a B-Cap. Owners or Operators that elect to comply with a B-Plan will be required to meet equipment specific interim NOx Concentration Limits or NOx emission rates. On the other hand, the owners or operators that elect to comply with the B-Cap are not held to the individual interim NOx Concentration Limits since those Facilities are operating under a facility-wide mass emissions cap. However, any Units outside of the B-Cap will be required to meet the interim NOx Concentration Limits upon exiting RECLAIM, before being subject to another NOx limits in PR 1109.1. The provision for the B-Cap is needed as PR 1109.1 allows operators to exclude Boilers and Process Heaters less than 40 MMBtu/hour from the B-Cap. Any unit that is not included in the mass emissions cap under the B-Cap, will be required to meet the Interim NOx Concentration limit under Table 3 of PR 1109.1 upon exiting RECLAIM.

Interim NOx and CO Concentration Limits – Table 3

PR 1109.1 includes interim NOx Concentration Limits that are based on permit limits and actual emissions data. Except for interim NOx Concentration Limits for Boilers and Process Heaters 40 MMBtu/hour and greater, all interim limits are a specific NOx concentration limit and are provided in Table 3 of PR 1109.1 and are presented below. All interim limits provide a 365-day averaging period which is proposed to minimize disruptions as Facilities transition out of RECLAIM.

Table 2.4-4: PR 1109.1 Table 3 – Interim NOx and CO Concentration Limits

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers and Process Heaters <6 MMBtu/hour[2]	60	400	3	365-day
Boilers and Process Heaters ≥6 MMBtu/hour and <40 MMBtu/hour[2]	40	400	3	365-day
Boilers and Process Heaters ≥40 MMBtu/hour	Pursuant to paragraph (e)(2)	400	3	365-day
Flares	105	400	3	365-day
FCCUs	40	500	3	365-day
Gas Turbines fueled with Natural Gas or Other Gaseous Fuel	20	130	15	365-day
Petroleum Coke Calciner	85	2,000	3	365-day
SMR Heaters	20[3]	400	3	365-day
	60[4]			365-day
SMR Heaters with Gas Turbine	5	130	15	365-day
SRU/TG Incinerators	100	400	3	365-day
Sulfuric Acid Furnaces	30	400	3	365-day
Vapor Incinerators	110	400	3	365-day

1 Averaging times are applicable to Units with a CEMS and shall be calculated pursuant to Attachment A of this rule; compliance for Units without a certified CEMS shall be demonstrated pursuant to paragraph (l)(1).

2 Boilers and Process Heaters with a Rated Heat Input Capacity <40 MMBtu/hour that operate with a certified CEMS may comply with the NOx emission rate pursuant to paragraph (e)(2) in lieu of the NOx Concentration Limit in Table 3.

3 SMR Heaters equipped with post-combustion air pollution control equipment that was installed before [DATE OF ADOPTION].

4 SMR Heaters not equipped with post-combustion air pollution control equipment as of [DATE OF ADOPTION].

Interim Limits for Boilers and Process Heaters for Facilities Complying with Table 1 or Table 2, or a B-Plan – Paragraph (e)(2)

For Boilers and Process Heaters with a Rated Heat Input Capacity greater than or equal to 40 MMBtu/hour, staff found substantial variation in the NOx concentration levels with no definitive groupings of Units to establish a specific NOx concentration limit. For owners or operators under an approved B-Plan, upon exiting RECLAIM when the facility becomes a Former RECLAIM Facility, the owner or operator must meet a 0.03 pounds/MMBtu over a rolling 365-

day average for all Boilers and Process Heaters that are greater than or equal to 40 MMBtu/hour and may include Boilers and Process Heaters that are less than 40 MMBtu/hour if they operate with a certified NOx CEMS. This provision would be effective on the day after the Facility becomes a Former RECLAIM Facility and calculated per Attachment A Section (A-2) of PR 1109.1. To demonstrate the rolling average the owner or operator will use the mass emissions from the prior 365 days, with emissions for 364 days to be based on emissions while the Facility was in RECLAIM and emissions for the 365th day will be based on the day the Facility became a Former RECLAIM facility. Subparagraph (e)(2)(B) requires subparagraph (e)(2)(A) to be implemented until the last Unit under this provision meets the final applicable NOx concentration limit in Table 1, Table2, or an approved B-Plan to ensure that as Units comply with the NOx concentration limit, the remaining units do not exceed the applicable threshold.

The calculation to determine a Facility's NOx levels is included in Attachment A Section (A-2) of PR 1109.1 and is as follows:

- Hour Mass Emissions (lbs/hour) Section (A-2.1)

  Sum the actual annual mass emissions of all Boilers and Process Heaters with a Rated Heat Input Capacity at or greater than 40 MMBtu/hour and any Boilers and Process Heaters with a Rated Heat Input Capacity less than 40 MMBtu/hour that operate a certified CEMS and divide by 8,760 hours for pounds per hour.

- Combined Maximum Rated Heat Input Capacity (MMBtu/hour) Section (A-2.2)

  Sum the combined maximum Rated Heat Input Capacity for all Boilers and Process Heaters with a Rated Heat Input Capacity at or greater than 40 MMBtu/hour and any Boilers and Process Heaters with a Rated Heat Input Capacity less than 40 MMBtu/hour that operate a certified CEMS.

- Interim Facility Wide NOx Emission Rate (lbs/MMBtu) Section (A-2.3)

  Divide the Hourly Mass Emissions in Section (A-2.1) by the combined Maximum Heat Input in Section (A-2.2) to determine the interim facility-wide NOx emission rate.

Interim Requirements for a Facility with a B-Cap – Paragraph (e)(3)

Facilities that elect to comply with a B-Cap will not be held to the NOx concentrations limits in Table 3 of PR 1109.1, with the exception of those Boilers and Process Heaters less than 40 MMBtu/hour that are not included in an approved B-Cap. Facilities under a B-Cap will be required to demonstrate on a daily bases, based a 365-day rolling average that they meet the Facility BARCT Emission Targets that are specified in subparagraph (h)(4)(D). If a facility exits RECLAIM before the implementation of the first Phase of an I-Plan, the emissions cap will be based on the Baseline NOx Emissions.

Subdivision (f) – Compliance Schedule

This subdivision establishes the implementation schedules for combustion equipment at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries to comply with PR 1109.1 requirements.

Compliance Schedule for Table 1 – Paragraph (f)(1)

This paragraph requires an owner or operator to submit a complete permit application to establish a NOx and Corresponding CO Limit in a permit on or before July 1, 2023. Owners or operators must meet the NOx and CO concentration limits in PR 1109.1 Table 1 from the date the Permit to

Operate is issued or no later than 36 months after a Permit to Construct is issued, whichever is sooner. Operators with a Permit to Construct or a Permit to Operate that already has an enforceable NOx concentration limit consistent with Table 1 are not required to submit a permit application. This is the only compliance pathway for Facilities with less than six Units. For Facilities with six or more Units, PR 1109.1 provides this compliance pathway as well as an alternative implementation schedule under the I-Plan.

It should be noted several of the rule provisions require "a complete permit application" to be submitted. A complete permit application includes, but not limited to, all signed forms with all applicable fields filled in, applicable fees, and additional information needed by the Executive Officer to make a determination. This is different than a permit that has been "deemed complete", which is the formal determination the Engineering Division makes when confirming all information has been received to properly conduct their analysis to process the permit. There are existing rules which dictate the criteria for a complete permit application:

1. The preamble to Reg. II – List and Criteria Identifying Information Required Of Applicants Seeking A Permit To Construct From The South Coast Air Quality Management District;
2. Rule 210 – Permit to Construct; and
3. Rule 3003 – Applications.

A complete permit application includes, but is not limited to, all signed forms with all applicable fields filled in, applicable fees, and additional information needed by the Executive Officer to make a determination. PR 1109.1 includes the phrase "complete permit application" to ensure the Facilities submit all required information in order for the South Coast AQMD to meet the tight timelines and issue the plans and permits in a timely manner.

Compliance Schedule for Boilers and Process Heaters Less Than 40 MMBtu/hour – Paragraph (f)(2)

The NOx limit of 40 ppmv for Boilers and Process Heaters less than 40 MMBtu/hour is lowered to 5 ppmv for Boilers and 9 ppmv for Process Heaters when the owner or operator either cumulatively replaces 50 percent or more of the burners or the burners replaced cumulatively represent 50 percent or more of the Heat Input. The cumulative burner replacement provisions apply from a specified date to prevent a facility from replacing burners incrementally over time in order not to trigger a retrofit. The compliance schedule to achieve the two-step NOx Concentration Limits are provided in Table 4 of PR 1109.1, provided as Table 3-6 below. Additionally, owners or operators are required to maintain records for burner replacement for these boilers and process heaters to track burner replacement.

Boilers Less than 40 MMBtu/Hour

The first NOx Concentration Limit for Boilers less than 40 MMBtu/hour, pursuant to subparagraph (d)(2)(A), is 40 ppmv. Complete permit applications must be submitted by July 1, 2022, and the compliance date begins when South Coast AQMD issues the Permit to Operate as all of these units are currently achieving less than 40 ppmv NOx.

The second NOx Concentration Limit is 5 ppmv pursuant to subparagraph (d)(2)(B). The complete permit applications are due based on burner replacement and is due no later than six months from the either when 50 percent or more of the burners are cumulatively replaced or the burners replaced cumulatively represent 50 percent or more of the Heat Input, with the cumulative replacement of burners beginning to be effective from July 1, 2022. The Boiler will be required to meet the 5 ppmv NOx limit 18 months from the date the Permit to Construct is issued by South Coast AQMD.

Process Less than 40 MMBtu/Hour

The first NOx Concentration Limit for these Process Heaters less than 40 MMBtu/hour, pursuant to subparagraph (d)(2)(A), is 40 ppmv and complete permit applications must be submitted by July 1, 2023. The compliance date begins when South Coast AQMD issues the Permit to Operate or 18 months from the date the Permit to Construct is issued by South Coast AQMD, whichever is sooner. Additionally, Facilities have the option to immediately meet the second step NOx concentration limit of 9 ppmv. For these Facilities, the compliance date will be 36 months from the date the Permit to Construct is issued by South Coast AQMD. PR 1109.1 includes a longer compliance schedule to implement the lower NOx limit to incentivize early adoption of the emerging technologies.

The second NOx Concentration Limit is 9 ppmv pursuant to subparagraph (d)(2)(C). Since the emission reduction technologies for Process Heaters are based on emerging technologies, the NOx limit of 9 ppmv is effective ten years after rule adoption to provide time for the emerging technologies to further develop. The complete permit applications are due based on burner replacement, no later than six months from the either when 50 percent or more of the burners are cumulatively replaced or the burners replaced cumulatively represent 50 percent or more of the Heat Input, with the cumulative replacement of burners beginning to be effective beginning five year after rule adoption with the compliance date will be 18 months from the date the Permit to Construct is issued by South Coast AQMD. Most, but not all, Process Heaters less than 40 MMBtu/hour are currently achieving the first 40 ppmv NOx limit; however, several Units will have to be retrofit. The five-year time allowance to begin counting the cumulative burner replacement is to address the time needed to retrofit those units to meet the 40 ppmv NOx limit.

Staff believes that implementation of the B-Plan and B-Cap will help incentivize owners or operators to accelerate introduction and commercialization of emerging technologies. Staff will monitor the development of the emerging technologies and will include in the Resolution a commitment to report on the status of the emerging technologies in 2029 and conduct a technology assessment if these technologies are not being commercialized.

Table 2.4-5: PR 1109.1 Table 4 – Compliance Schedule for Boilers and Process Heaters Less Than 40 MMBtu/Hour

Unit	NOx Concentration Limit (ppmv)	Permit Application Submittal Date	Compliance Date
Boilers <40 MMBtu/ hour	40 ppmv pursuant to subparagraph (d)(2)(A)	On or before July 1, 2022	• On and after the date the South Coast AQMD issues a Permit to Operate
	5 ppmv pursuant to subparagraph (d)(2)(B)	Pursuant to subparagraph (f)(2)(B)	• On and after 18 months from the date the South Coast AQMD issues a Permit to Construct
Process Heaters <40 MMBtu/ hour	40 ppmv pursuant to subparagraph (d)(2)(A)	On or before July 1, 2023	• On and after the date the South Coast AQMD issues the Permit to Operate or on and after 18 months from the date the South Coast AQMD issues a Permit to Construct, whichever is sooner; or • On and after 36 months from the date the South Coast AQMD issues a Permit to Construct if the owner or operator of a Facility elects to meet the NOx concentration limit pursuant to subparagraph (d)(2)(C) in lieu of subparagraph (d)(2)(A)
	9 ppmv pursuant to subparagraph (d)(2)(C)	Pursuant to subparagraph (f)(2)(C)	• On and after 18 months from the date the South Coast AQMD issues a Permit to Construct

Compliance Schedule for Table 2 Conditional Limit – Paragraph (f)(3)

PR 1109.1 allows an owner or operator that meets the conditions specified in paragraph (d)(3) to elect to meet Conditional NOx and Corresponding CO Concentration Limits in Table 2 in lieu of Table 1 Limits. If Facilities use this option, they must submit a complete permit application on or before June 1, 2022 to establish a condition to limit the NOx and CO emissions to a level not to exceed the applicable Table 2 Conditional NOx and Corresponding CO Concentration Limits and meet that limit no later than the date the Permit to Operate is issued or 18 months from the date the Permit to Construct is issued, whichever is sooner. Staff is proposing 18 months to meet the NOx concentration limit since the conditional limits were intended for those Units that are currently achieving NOx levels that are near the Table 2 limits and little to no physical modifications to the Unit are needed. Staff is proposing June 1, 2022 to provide lead time prior to the submittal of an I-Plan, B-Plan, and B-Cap. A commitment that an owner or operator will be meeting the conditional NOx limit is needed to allow an owner or operator to account for a Unit that is seeking compliance with Table 2 in lieu of Table 1 NOx limits when calculating the Facility BARCT Emission Target. Implementation of the conditional limits by requiring a permit application by July 1, 2022 will help to expedite BARCT implementation consistent with AB 617.

Modifications to Existing Units that are Meeting Table 2 Conditional NOx Concentration Limits – Paragraph (f)(4)

Paragraph (f)(4) includes provisions for owners or operators that significantly modify existing pollution controls on a Unit that were previously meeting the Table 2 Conditional NOx and Corresponding CO Concentration Limits. Under subparagraph (f)(4)(A), an owner or operator meeting the Table 2 Conditional NOx and Corresponding CO Concentration Limits will be required to submit a complete permit application prior to replacing the exiting NOx control equipment to accept the NOx Concentration Limit and Corresponding CO Concentration Limit in Table 1 if replacing: (1) an existing with a new post-combustion air pollution control equipment; (2) components of existing post-combustion air pollution control equipment; and (3) burners for Vapor Incinerators.

Clauses (f)(4)(A)(i) and (f)(4)(A)(ii), include provisions for replacement of existing post-combustion controls or the replacement of components of post-combustion controls applies to FCCUs, Gas Turbines fueled with Natural Gas, Process Heaters with a Heat Input Capacity at or greater than 40 MMBtu/hour, and SMR Heaters. Additionally, the provision for replacing components, clause (f)(4)(A)(ii), applies if the cost of the components being replaced is greater than 50 percent of the fixed capital cost that would be required to construct and install new post-combustion air pollution control equipment. Clause (f)(4)(A)(ii), applies to burner replacement for vapor incinerators, where replacement is based on if 50 percent or more of the burners are cumulatively replaced or the burners replaced cumulatively represent 50 percent or more of the Heat Input Capacity, where the cumulative replacement begins on rule adoption. This provision is to ensure if an owner or operator is making a significant modification to the listed equipment, the owner or operator will then be required to meet the Table 1 NOx and Corresponding CO Concentration Limits. Under subparagraph (f)(4)(B), the owner or operator must meet the Table 1 NOx Concentration Limit and Corresponding CO Concentration Limit no later than the date the Permit to Operate is issued or 18 months from the date the Permit to Construct is issued, whichever is sooner.

Exempted Units – Paragraph (f)(5)

Paragraph (f)(5) requires owners or operators with Units that are exempt pursuant to PR 1109.1 paragraphs (o)(2), (o)(3), (o)(5), (o)(6), (o)(8) and (o)(9) to submit a complete permit application by July 1, 2022 to meet the applicable limits required by the exemption. The applicable limits for the exemptions are as follows:

- Paragraphs (o)(2) and (o)(5), hours of operation per calendar year;
- Paragraph (o)(3), Rated Heat Input Capacity per calendar year;
- Paragraph (o)(6), Heat Input per calendar year; and
- Paragraphs (o)(8) and (o)(9), pounds of NOx per calendar year.

Exempted Units Exceeding Limits – Paragraph (f)(6)

Certain Units are exempt from the NOx and Corresponding CO Concentration Limits in Table 1, but have different applicable limits (e.g., hours of operation per calendar year or pounds of NOx per calendar year). Paragraph (f)(6) includes provisions for an owner or operator that exceeds the limits in required by the exemption. A complete permit application to meet the applicable NOx and Corresponding CO Concentration Limit in Table 1 must be submitted within six months of the exceedance. The deadline to comply with the Table 1 limits is no later than the date the Permit to Operate is issued or 18 months from the date the Permit to Construct is issued, whichever is sooner. Any unit that was exempt, and exceeds a limit is no longer exempt, cannot be included in B-Plan, B-Cap, or I-Plan and must comply with Table 1 limits.

Failure to Submit a Permit Application - Paragraph (f)(7)

Paragraph (f)(7) includes provisions for an owner or operator that fails to submit a permit application on time. This provision is to ensure that if an owner or operator submits a permit application late, the owner or operator will not be afforded additional time to meet the NOx and Corresponding CO limit. Under this provision, if an owner or operator fails to submit a permit application by the deadline in PR 1109.1, the owner or operator shall meet the applicable NOx Concentration Limit either 36 or 24 months from when the permit application is submitted, as compared to when the permit to construct is issued for most provisions under PR 1109.1. This provision is designed to strongly discourage late submittals of permit applications.

Provisional Averaging Time – Paragraph (f)(8)

During the rulemaking process some owners or operators commented that achieving the shorter averaging times and lower NOx Concentration Limits in PR 1109.1 will be challenging as owners or operators are currently accustomed to an annual compliance cycle under the RECLAIM program. Achieving the PR 1109.1 NOx Concentration Limits in Table 1 and Table 2 will require shorter compliance periods for all Units other than the FCCUs, Petroleum Coke Calciners, and Sulfuric Acid Plants, which will be subject to 365-day rolling averages. To address this additional challenge, for Units with an approved CEMS and subject to a rolling average less than 365 days, compliance with the NOx Concentration Limits or Alternative BARCT NOx Limits, and Corresponding CO Concentration limits must be demonstrated six months after the issuance of the Permit to Operate, 36 months after the Permit to Construct is issued, or immediately after completion of a compliance demonstration source test, whichever is soonest. This consideration allows for applying any necessary adjustments to ensure NOx emission levels can be met within the required averaging times.

Initial Averaging Time for Units with a 365-Day Averaging Time Period – Paragraph (f)(9)

An owner or operator of a Unit subject to a 365-day rolling average shall demonstrate compliance with the applicable NOx Concentration Limit or Alternative BARCT NOx Limit beginning 14 months after the South Coast AQMD Permit to Operate is issued, 36 months after the Permit to Construct is issued, or immediately after completion of a compliance demonstration source test, whichever is soonest. This consideration allows for applying any necessary adjustments to ensure NOx emission levels can be met within the required averaging times.

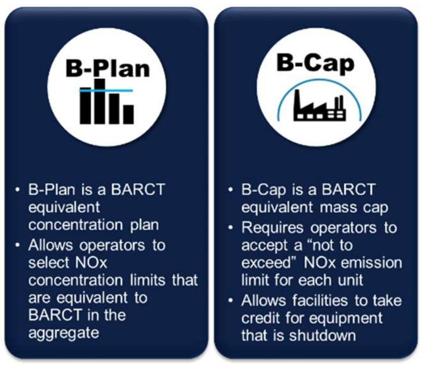
Decommissioned Units – Paragraph (f)(10)

Units that will be decommissioned to comply with this rule will need to: 1.) surrender the Unit's Permit to Operate; 2.) disconnect and blind the Unit's fuel lines; and 3.) not sell the Unit for operation within the South Coast Air Basin.
The compliance schedule for decommissioned Units is dependent on which plan the Facility elects.

- If the Unit is excluded from a B-Plan, then the owner or operator shall comply within 54 months from the Phase I Permit Application Submittal Date specified in Table 6 for the I-Plan option selected.
- If an approved B-Plan is modified to remove a Unit that will be decommissioned, then the owner shall comply by the date specified by the Executive Officer.

- If a New Unit is replacing an entire or part of a decommissioned Unit to meet the requirements of an approved B-Cap and an approved I-Plan, then owner or operator shall comply within 90 days from commissioning a New Unit.
- If a Unit is to be decommissioned and not being replaced with a New to meet the requirements of an approved B-Cap and an approved I-Plan, then owner or operator shall comply no later than the B-Cap Effective Date of the Facility BARCT Emission Target specified in Table 6 for the I-Plan option selected for a B-Cap.

Subdivision (g) – B-Plan and b-cap requirements



PR 1109.1 includes two alternative compliance options to directly meeting the NOx Concentration Limits in Table 1 or Table 2 for owners or operators with six or more Units. These alternative compliance options were developed to address the complexity of operations at Petroleum Refineries and Facilities With Related Operations To Petroleum Refineries, recognizing that achieving the Table 1 NOx Concentration Limits may be more challenging for some Units, as owners or operators are integrating new pollution control equipment on existing Units within the existing configuration of their Facility. The B-Plan is a BARCT Equivalent Compliance Plan and is designed to achieve the NOx and CO Concentration Limits in Table 1 and Table 2, in aggregate. The B-Cap is a BARCT Equivalent Mass Cap Plan and is designed to achieve the NOx Concentration Limits in Table 1 and Table 2, based on aggregate mass emissions. Both the B-Plan and B-Cap are designed to achieve similar NOx emission reductions as if owners or operators were directly complying with Table 1 and Table 2 NOx and CO Concentration Limits.

Paragraphs (g)(1) and (g)(2) establish the requirements for the B-Plan and B-Cap, respectively. Owners or operators that elect to use an alternative compliance option, must select either the B-Plan or the B-Cap and submit the plan on or before September 1, 2022. Both the B-Plan and the B-Cap require owners or operators to submit a permit application to limit the NOx concentration to the selected Alternative BARCT NOx Limit for each Unit. Implementation of projects to achieve the Alternative BARCT NOx Limit in the B-Plan and the B-Cap are based on the schedule in the approved I-Plan. At full implementation, all Units regulated under PR 1109.1 will have an enforceable NOx concentration permit limit.

Requirements for the B-Plan - Paragraph (g)(1)

Under the B-Plan, owners or operators select an Alternative BARCT NOx Limit for each Unit. If the owner or operator can meet the conditions of the Conditional NOx Concentration Limits under paragraph (d)(3), the Alternative BARCT NOx Limit cannot exceed the Table 2 NOx Concentration Limit, with the exception of any Unit identified in Table D-1 of PR 1109.1. Pursuant to paragraph (d)(3), a Unit listed on Table D-1 is not limited to the NOx concentration limits in Table 2 and the owner or operator can submit complete permit applications for these Units based on the established Alternative BARCT NOx Limits in the approved I-Plan.

BARCT EQUIVALENT COMPLIANCE PLAN (B-PLAN) means a compliance plan that allows an owner or operator of a Facility to select Alternative BARCT NOx Limits for all Units subject to the B-Plan that will achieve emission reductions that are greater in the aggregate than the mass emission reductions that would be achieved based on the NOx Concentration Limits in Table 1 – NOx and CO Concentration Limits (Table 1) or Table 2 – Conditional NOx and CO Concentration Limits (Table 2).

An owner or operator that elects to meet the Table 1 and Table 2 NOx Concentration Limits and Corresponding CO Limits through implementation of a B-Plan is required to:

- Submit a B-Plan on or before September 1, 2022;
- Identify all Units subject to the Rule 1109.1 B-Plan
- Select an Alternative BARCT NOx Limit for each Unit and calculate the BARCT Equivalent Mass Emissions, with specific requirements for Units meeting the Conditional NOx Concentration Limits; and
- Not include any Unit that has been or will be decommissioned.

Units to be Included in the B-Plan – Subparagraph (g)(1)(B)

Under the B-Plan, all Units are to be included in the B-Plan with a few exceptions. Pursuant to subparagraph (g)(1)(B) Units that can be excluded include Optional Units, which are Boilers or Process Heaters with a Rated Heat Input Capacity of less than 40 MMBtu/hour that will meet the NOx concentration limits pursuant to subparagraph (d)(2)(B) or (d)(2)(C); Units that will be decommissioned 54 month from the permit submittal date of Phase I of the selected I-Plan, and some units that are exempt from the NOx Concentration Limits in Table 1 because they are low use under paragraphs (o)(2) (low-use boilers < 40 MMBtu/hr), (o)(5) (FCCU boilers or process heaters operating less than 200 hours per year), (o)(6) (startup or shutdown boilers and process heaters using less than 90,000 MMBtu annually), (o)(8) (flares that emit ≤ 550 of NOx per year, and (o)(9) (vapor incinerators emitting less than 100 pounds of NOx per year for unlimited exemption or less than 1,000 pound of NOx per year for limited exemption), and Units listed under paragraph (o)(1) (boilers or process heaters ≤ 2 MMBtu/hr used for comfort heating) shall not be included in the B-Plan. Any Unit that has been decommissioned should not be included in the B-Plan.

With regard to the B-Plan, in communication with U.S. EPA, the B-Plan will result in an environmental benefit by requiring BARCT Equivalent Mass Emissions, based on Alternative BARCT limits, to be less than (not equal to) the Facility BARCT Emission Target, which is derived from applicable BARCT NOx limits in Table 1 and Table 2. In addition, the B-Plan does not allow shutdowns and the Alternative BARCT NOx limits used in the B-Plan are either at or below RACT.

Calculating the BARCT Equivalent Mass Emissions -Subparagraph (g)(1)(C)

The methodology for calculating the BARCT Equivalent Mass Emissions is presented in Attachment B. Subparagraph (g)(1)(C) specifies parameters for the NOx concentration values that must be used in this calculation. The operator is responsible for selecting the Alternative BARCT NOx Limit and identifying which phase that the Alternative BARCT NOx Limit will be implemented. For an I-Plan, for any Unit that meets the conditions for Table 2 NOx Concentrations because the operator has submitted a permit application by June 1, 2022, must limit the Alternative BARCT NOx Limit to Table 2 NOx Concentrations. This provision clarifies that any Unit where the Alternative NOx BARCT Limit has not yet been identified for a phase of the I-Plan, that the Representative NOx Concentration which would be representative of the Baseline NOx Emissions will be used to calculate the BARCT Equivalent Mass Emissions and is for the purpose calculating the BARCT Equivalent Mass Emissions. This section also requires that the operator demonstrate that by the final phase of the I-Plan, each Unit will be assigned an Alternative BARCT NOx Limit.

Implementation of an Approved B-Plan – Paragraph (g)(2)

Paragraph (g)(2) establishes the requirements after approval of an I-Plan and B-Plan pursuant to paragraph (i)(4). After an owner or operator receives approval of an I-Plan and B-Plan, the operator is required to submit a complete Permit application to apply for a condition that limits the NOx limits not to exceed the Alternative BARCT NOx Limit and Corresponding CO Limits based on the schedule in the approved I-Plan. An operator must not operate a Unit unless the NOx and CO concentration levels are below the Alternative BARCT NOx Limits. By the final implementation phase in the I-Plan, an Alternative BARCT NOx Limit must be identified for each Unit in the I-Plan, where the permit application submittal is based on the dates in approved I-Plan. An Alternative BARCT NOx Limit is required for all Units in the I-Plan, regardless of if the Unit is modified to add pollution controls. This ensures that each Unit has an enforceable NOx concentration limit for each Unit in the I-Plan.

Requirements for the B-Cap - Paragraph (g)(3)

Under the B-Cap, the requirements are the same as for an operator that elects to use a B-Plan for the provisions listed above, with the exception of provisions for using Table 2 Conditional Limits. Since decommissioned Units are allowed under the B-Cap the provision to remove a Unit that will be decommissioned within Phase I is not included in the B-Cap. In addition, there are additional provisions for the B-Cap to provide safeguards to ensure the B-Cap remains equivalent to Table 1 and Table 2 NOx Concentration Limits based on aggregate mass emissions. These additional provisions are discussed below.

B-CAP means a compliance plan that establishes a Facility mass emission cap for all units subject to the B-Cap that, in the aggregate, is less than the Final Phase Facility BARCT Emission Target.

Calculating the BARCT Equivalent Mass Emissions - Subparagraph (g)(3)(C)

The methodology for calculating the BARCT Equivalent Mass Emissions is presented in Attachment B. Subparagraph (g)(3)(C) specifies parameters for the NOx concentration values that must be used in this calculation. The provisions are identical to the B-Plan, with one additional criteria that while the Representative NOx Concentration may exceed Maximum Alternative BARCT NOx Concentration Limits in Table 5, however, the Alternative NOx BARCT Limit cannot exceed the Maximum Alternative BARCT NOx Concentration Limits for a B-Cap pursuant to Table 5 of PR 1109.1. Similar to the discussion for the B-Plan, the use of the Representative NOx Concentration is for calculating the BARCT Equivalent Mass Emissions.

Table 2.4-6: PR1109.1 Table 5 – Maximum Alternative BARCT NOx Concentration Limits for a B-CAP

Unit	Maximum Alternative BARCT NOx Limit	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers and Process Heaters <40 MMBtu/hour	40 ppmv	3	24-hour
Boilers and Process Heaters ≥40 MMBtu/hour	50 ppmv	3	24-hour
FCCUs	8 ppmv	3	365-day
	16 ppm		7-day
Gas Turbines	5 ppmv	15	24-hour
Petroleum Coke Calciners	100 tons/year	N/A	365-day
SMR Heaters	12 ppm	3	24-hour
SRU/TG Incinerators	100 ppmv	3	24-hour
Vapor Incinerators	40 ppmv	3	24-hour

[1] Averaging times apply to Units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule; compliance for Units without a certified CEMS shall be demonstrated pursuant to paragraph (l)(1).

Calculating the BARCT B-Cap Annual Emissions – Subparagraph (g)(3)(D)

Under the B-Cap, operators have three mechanisms to reduce mass emissions: (1) Lower the NOx concentration level of the Unit; (2) decommissioning units, and (3) implement other emission reduction strategies such as reduced throughput, capacity, or any other emission reduction strategy that would lower mass emissions. Under the B-Cap, operators can use any of the three emission reduction strategies to reduce mass emissions from Units in the B-Plan but must also demonstrate daily that actual emissions are below the Facility BARCT Emission Target based a rolling 365-day average. In addition, the Facility BARCT Emission Target is based on Table 1 and Table 2 NOx Concentration Limits, plus an additional 10 percent reduction to benefit the environment. This is a 10 percent reduction in NOx, that operators that use a B-Cap are required to achieve. The 10 percent environmental benefit is included to meet U.S. EPA guidelines for economic incentive programs. U.S. EPA views the B-Cap as an economic incentive program as it allows trading of emission reductions within a facility emissions cap and allows the use of reductions from decommissioned Units to meet emission reduction obligations. For a more detailed discussion of the 10 percent environmental benefit, refer to the section on Subdivision (h) of PR 1109.1 in the Staff Report.

BARCT B-CAP ANNUAL EMISSIONS means the sum of the mass emissions from the Unit B-Cap Annual Emissions for each phase of an I-Plan, that is based on the Alternative BARCT NOx Limits, decommissioned Units, and other emission reduction strategies to meet the Facility BARCT Emission Targets in an I-Plan as calculated pursuant to Attachment B of this rule.

Implementation of a B-Cap – Paragraph (g)(4)

Paragraph (g)(4) establishes the requirements after approval of an I-Plan and B-Cap pursuant to paragraph (i)(4). After an owner or operator receives approval of an I-Plan and B-Plan, the operator is required to submit a complete Permit application to apply for a condition that limits the NOx limits not to exceed the Alternative BARCT NOx Limit and Corresponding CO Limits based on the schedule in the approved I-Plan.

Not Operate a Unit above the Alternative BARCT NOx Limit – Subparagraph (g)(4)(B)

Subparagraph (g)(4)(B) specifies that a Unit cannot exceed the Alternative BARCT NOx Limit based on the schedule in the approved I-Plan. By the final implementation phase in the I-Plan, an Alternative BARCT NOx Limit must be identified for each Unit in the I-Plan, where the permit application submittal is based on the dates in approved I-Plan. An Alternative BARCT NOx Limit is required for all Units in the I-Plan, regardless of if the Unit is modified to add pollution controls. This ensures that each Unit has an enforceable NOx concentration limit for each Unit in the I-Plan.

Decommissioned Units Under the B-Cap – Subparagraph (g)(4)(C)

Under the B-Cap, an operator can permanently decommission a Unit to meet the Facility BARCT Target since emissions from all units are “capped” and the facility is meeting BARCT based on mass emissions. The owner or operator of a Unit that elects to decommission a Unit under a B-Cap is required to reflect the emissions from the decommissioned unit as Table 1 emissions in the Final Phase Facility BARCT Emission Target. For any Unit that is decommissioned, the South Coast AQMD Permit to Operate must be surrendered, and the owner shall disconnect and blind the fuel line(s) to the unit and not sell the unit for operation to another entity within the South Coast Air Basin. Provisions for decommissioning a Unit and the schedule to decommission a Unit are discussed under paragraph (f)(10).

Daily Demonstration that Units in the B-Cap are Below the Facility BARCT Emission Target – Subparagraph (g)(4)(D)

It is expected that operators that are using a B-Cap will have higher Alternative BARCT NOx Concentration Limits for each individual Unit compared to Units under the B-Plan. However, the B-Cap has two additional safeguards to address this issue. The first provision limits the Alternative BARCT NOx Concentration Limits to ensure that each Unit has pollution controls (subparagraph (g)(4)(B)). Under PAR 1109.1, the Alternative BARCT NOx Limits cannot exceed the Maximum Alternative NOx Concentration Limits in Table 5 of PR 1109.1. The second provision is the mass emissions cap, and the daily demonstration that operators are below the Facility BARCT Emission Target based on a rolling 365-day average (subparagraph (g)(4)(D)). This ensures that although some Units will individually have higher Alternative BARCT NOx Concentration Limits the operation of these, and all Units cannot exceed the mass emissions cap. Although Alternative NOx Concentrations may be higher than those under a B-Plan and the B-Cap some additional flexibilities such as the use of decommissioned Units and other emission reduction strategies, this second compliance component ensures that mass emissions, based on an annual average, are representative of the Units meeting Table 1 and Table 2 NOx Concentration Limits. It should also be noted, that under the B-Plan mass emissions are not capped, while emissions under the B-Plan are.

Provisions for New Units – Subparagraph (g)(4)(E)

PR 1109.1 has additional provisions for operators with a B-Cap for New Units. PR 1109.1 requires that the operator demonstrates that one or more of the following criteria are met before a New Unit is added to the Facility. The operator is also required to provide in writing at the time the permit application is submitted for the New Unit, which of the conditions have been met.

- The unit for which permit application is being submitted is not subject to this rule or is a Unit that will meet an exemption pursuant to paragraphs (o)(1), (o)(2), (o)(3), (o)(5), (o)(6), (o)(8), or (o)(9), if the operator met this condition the New Unit would not need to be added to the B-Cap. The New Unit must meet all of the requirements including any permit condition for limiting hours of operation or fuel usage that is specified in subdivision o for those exemptions.

- The BARCT Equivalent Mass Emissions with the New Unit is below the Facility BARCT Emission Target for the current and any future phase of the I-Plan, as calculated in Attachment B, if the operator met this condition the New Unit would not need to be added to the B-Cap. This provision is the same criteria used for a B-Plan and ensures that all Units that were not decommissioned meet the NOx Concentration Limits in Table 1 and Table 2 in aggregate, where no emissions budget from a Unit that was decommissioned can be used to establish a higher Alternative NOx Concentration Limit.
- The New Unit is not Functionally Similar to any Unit that was decommissioned in the approved B-Cap and the New Unit will not increase the overall facility throughput, if the operator met this condition the New Unit would not need to be added to the B-Cap;
- The total amount of NOx emission reductions from units that were decommissioned, represents 15 percent or less of the Final Phase Facility BARCT Emission Target in an approved B-Cap and the B-Cap is modified to include the New Unit and the Facility BARCT Emission Target is adjusted to incorporate the New Unit;
- The New Unit is Functionally Similar to any Unit that was decommissioned, and the B-Cap is modified with no increase of the Facility BARCT Emission Target. Any Unit that was decommissioned had an emissions budget in the B-Cap that was based on the Table 1 NOx Concentration Limit. Staff believes any New Unit that is Functionally Similar, which includes Units that are different equipment categories but provide the same purpose, should not be allowed to have an additional emissions budget in the Facility BARCT Emission Target.

The provisions for new units and unit decommissioning are to prevent a facility from shutting down units instead of installing controls on units. While shutting down a unit will result in emission reductions, the intent of PR 1109.1 is to require facilities to have BARCT levels of control on all units, or BARCT equivalent emissions in the aggregate. If a facility were to decommission a unit, take credit for the emission reductions in the B-CAP, and later install a functionally similar unit outside the B-Cap, the B-Cap would no longer be BARCT equivalent. It would not be equitable that the emissions budget from decommissioning a unit was used to allow another unit to not install pollution controls, and later install a unit that is functionally similar to the unit that was decommissioned.

Subdivision (h) - I-Plan Requirements

An I-Plan is compliance plan that provides an alternative implementation schedule to the compliance schedule in paragraph (f)(1) which would require that all permits be submitted by January 1, 2023. An I-Plan is required for facilities that elect to comply with either a B-Plan or a B-Cap or a facility that elects to have an alternative compliance schedule for meeting Table 1 or Table 2 NOx Concentration Limits and Corresponding CO Concentration Limits.

General Requirements of an I-Plan – Paragraph (h)(1)

An owner or operator that elects to implement an I-Plan, must submit an I-Plan pursuant to paragraph (i)(1). Similar to the B-Plan and B-Cap, the I-Plan is only for Facilities with six or more Units. The I-Plan must include all of the Units included in the accompanying B-Plan if the Facility is electing to comply with a B-Plan and all of the Units included in the accompanying B-Cap if the facility is electing to comply the B-Cap. Operators do have the option to comply with the Table 1 or Table 2 limits using an alternative schedule in an I-Plan, for those operators the I-Plan must include all units at the Facility subject to the rule with the option to exclude "Optional Units" and Units that are complying with the rule under one of the exemption in under paragraphs (o)(2), (o)(5), (o)(6), (o)(8), and (o)(9). Units listed in paragraph (o)(1) shall not be included in the I-Plan as those units are subject to 1146.1 and will not be subject PR 1109.1.

The Units included in the I-Plan must be located at either a single Facility or Facilities Identify all Facilities With The Same Ownership and the owner or operator must identify the Facilities, identified by the facility identification numbers, in the I-Plan.

Selecting an I-Plan Option – Paragraph (h)(2)

OPTIONAL UNITS are Boilers or Process Heaters less than 40 MMBtu/hour that will meet the NOx concentration limits pursuant to subparagraph (d)(2)(B) or (d)(2)(C).

The I-Plan allows refineries to implement projects within their turnaround schedules to minimize operational disruptions. Staff consulted with refineries to develop the five I-Plan options and timeframes and percent reductions. Each of the five I-Plan options have specific use criteria, such as implementation of a B-Plan, a B-Cap, or meeting Table 1 and Table 2 NOx Concentration Limits. I-Plan Option 2 and Option 3 is only available to the owner or operator of a facility that is achieving a NOx emission rate of less than 0.02 pound per million BTU of heat input for all the Boilers and Process Heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour or any Boiler or Process Heater with a rated heat input capacity of less than 40 MMBtu/hours that operates with a certified CEMS, based on the Maximum Rated Heat Input Capacity. The facility would be required to perform a one-time demonstration that their applicable boilers and process heaters meet the 0.02 pound per million BTU emission rate based on the 2021 annual emissions for those units as reported in the 2021 Annual Emissions Report.

Table 6 lists the key elements of the each of the I-Plan options. The emission reductions are phased-in in either two or three. The "Percent Reduction Targets" are the percent reduction for each phase of the selected I-Plan that are applied to the total reductions required for each Facility. The "Permit Application Submittal Date" is the date that permits must be submitted to establish an Alternative BARCT NOx Limit. The "Compliance Schedule" is the timeframe the facility has to meet the Alternative BARCT NOx Limit for each Phase. By the last phase of the I-Plan, all units must have a permit condition that limits the units to the Alternative BARCT NOx limit for a facility complying with either a B-Plan or a B-Cap, or the Table 1 or Table 2 NOx concentration limits. For a B-Cap, Table 6 specifies the "B-Cap Effective Date of the Facility BARCT Emission Target" which represents the first day of the 365 days that will be used to calculate the 365-day rolling average. The compliance demonstration for the 365-day rolling average begins 365 days after the B-Cap Effective Date.

Table 2.4-7: Table 6 – I-Plan Percent Reduction Targets of Required Reductions and Compliance Schedule

I-Plan Option	Key Elements	Phase I	Phase II	Phase III
I-Plan Option 1 for B-Plan or Concentration Limits in Table 1 or Table 2	**Percent Reduction Targets**	**80**	**100**	**N/A**
	Permit Application Submittal Date	January 1, 2023	January 1, 2031	N/A
	Compliance Schedule	No later than 36 months after a Permit to Construct is issued		N/A
I-Plan Option 2 for B-Plan Only pursuant to subparagraph (h)(2)(E)	**Percent Reduction Targets**	**65**	**100**	**N/A**
	Permit Application Submittal Date	July 1, 2024	January 1, 2030	N/A
	Compliance Schedule	No later than 36 months after a Permit to Construct is issued		N/A
I-Plan Option 3 for B-Plan or B-Cap pursuant to subparagraph (h)(2)(E)	**Percent Reduction Targets**	**40**	**100**	**N/A**
	Permit Application Submittal Date	July 1, 2025	July 1, 2029	N/A
	Compliance Schedule	No later than 36 months after a Permit to Construct is issued		N/A
	B-Cap Effective Date of the Facility BARCT Emission Target	January 1, 2030	January 1, 2034	N/A
I-Plan Option 4 for B-Cap Only	**Percent Reduction Targets**	**50**	**80**	**100**
	Permit Application Submittal Date	N/A	January 1, 2025	January 1, 2028
	Compliance Schedule	January 1, 2024	No later than 36 months after a Permit to Construct is issued	
	B-Cap Effective Date of the Facility BARCT Emission Target	January 1, 2024	July 1, 2029	July 1, 2032
I-Plan Option 5 for B-Plan Only or Concentration Limits in Table 1 or Table 2	**Percent Reduction Targets**	**50**	**70**	**100**
	Permit Application Submittal Date	January 1, 2023	January 1, 2025	July 1, 2028
	Compliance Schedule	No later than 36 months after a Permit to Construct is issued		

The I-Plan schedule in Table 6 includes a 36-month compliance timeline to complete all of the NOx reduction projects included in each phase. Staff does not view the implementation period provided in Table 6 to be in conflict with Rule 205 that states "A permit to construct shall expire one year from the date of issuance unless an extension of time has been approved in writing by the Executive Officer." This rule and its general provisions will have the approval of the Executive Officer unless the rule requires an additional Executive Officer approval (e.g., an I-Plan, B-Plan, B-Cap, etc.).

Baseline NOx Emissions and Representative NOx Concentrations – Paragraph (h)(3)

Baseline NOx Emissions and Representative NOx Concentrations are used to calculate Final Phase Facility BARCT Emission Target, the Facility BARCT Emission Targets, and BARCT Equivalent Mass Emissions for each phase of the I-Plan. During the rulemaking process staff has been working with operators to ensure that the Baseline NOx Emissions and Representative NOx Concentrations for each Facility are accurate. Since this emissions data is important to approving any I-Plan, PR 1109.1 establishes a process for final revisions, and then the data will be formalized for use for the I-Plans and implementation of B-Plans and B-Caps.

A separate document titled "Baseline NOx Emissions and Representative NOx Concentrations for Facilities Regulated Under Rule 1109.1- Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations" will be presented to the South Coast AQMD Board for approval at the adoption Public Hearing for PR 1109.1. Pursuant to paragraph (f)(3), the Baseline NOx Emissions and Representative NOx Concentrations for each facility by Unit (listed by Unit ID) approved by the South Coast AQMD shall be used, unless the owners or operators request in writing a change, the Executive Officer approves the change, and if the changes are greater than five percent, the change is presented to the Stationary Source Committee no later than February 18, 2022. After any changes are presented to the Stationary Source Committee, operators cannot change the Baseline NOx Emissions or Representative NOx Concentrations for any Unit, and must use the approved values for all emissions calculations for the I-Plan, B-Plan, and B-Cap. This approach provides greater transparency and is expected to help reduce possible delays with approving I-Plans, B-Plans, and B-Caps.

FACILITY BARCT EMISSION TARGET means the total remaining NOx emissions that are based on the Percent Reduction Targets in each phase of a Table 6 I-Plan that are applied to the overall NOx emission reductions for the Units included in an approved B-Plan or B-Cap, as calculated pursuant to Attachment B of this rule.

NOx Concentration Limits for Final Phase Facility BARCT Emission Target – Paragraph (h)(4)

Paragraph (h)(4) specifies the NOx Concentration Limits that must be used to calculate the Final Phase Facility BARCT Emission Target. Operators must use Table 1 NOx Concentration Limits for any Unit that is not listed Table 3-8. PR 1109.1 also requires that for a Unit that is designated to be decommissioned under a B-Cap, for the NOx Concentration Limit in Table 1 must be used when calculating the Final Phase Facility BARCT Emission Target.

For the conditional NOx limits, there are two pathways that an operator can take to qualify to use the Conditional Limits in Table 2 to calculate the Final Phase Facility BARCT Emissions Target for a Unit. Both pathways are designed to achieve earlier NOx reductions to be consistent with the intent of AB 617.

- ✓ The first pathway is that the operator demonstrates that the Unit will meet the conditions to use the conditional NOx Concentration Limits pursuant to paragraph (d)(3) and submits a permit application on or before June 1, 2022 for a permit condition to limit the NOx to a level not to exceed the applicable conditional NOx Concentration Limit and Corresponding CO Concentration Limits in Table 2 pursuant to subparagraph (f)(3)(A).

✓ The second pathway is for Units that are identified in Attachment D of PR 1109.1. Any Unit listed in Attachment D, is "pre-qualified" and operators would submit a permit application during one of the phases of the I-Plan to establish the Alternative NOx Limit, which is not limited to the levels specified in Table 2. Table D-1 applies to facilities with a B-Plan or a B-Cap and includes those Boilers and Process Heater with a Rated Heat Input Capacity greater than or equal to 40 MMBtu/hour that were removed from the cost-effectiveness analysis for Table 1 due to either low emission reduction potential or high capital costs. Table D-2 applies only to facilities with a B-Cap that have selected I-Plan Option 4 and includes units that the South Coast AQMD staff has determined to meet all of the conditions in subparagraph (d)(3)(A) and Boilers and Process Heater with a Rated Heat Input Capacity greater than or equal to 40 MMBtu/hour that have a representative NOx concentration level at or below 25 ppmv. Table D-2 also includes Units that met the conditions under paragraph (d)(3) for Units other than Boilers and Process Heaters greater than or equal to 40 MMBtu/hour. Units listed under Table D-2 were added since an operator that is implementing I-Plan Option 4 will achieve 50 percent of their targeted emission reductions by January 1, 2024 and will be limited to using only the Units listed in Table D-2 at Table 2 limits when establishing the Final Phase Facility BARCT Emissions Target.

Table 2.4-8: NOx Concentration Limits for Final Phase Facility BARCT Target

<table>
<tr><th colspan="2">NOx Concentration Limit</th><th>Unit or Specific Provision for Unit</th></tr>
<tr><td colspan="2">Table 1 NOx Concentration Limits</td><td>Any Unit not listed below and Unit that will be decommissioned under a B-Cap</td></tr>
<tr><td rowspan="3">Table 2 Conditional NOx Limit</td><td rowspan="2">An operator that does not select I-Plan Option 4</td><td>Meets the conditions in paragraph (d)(3) and permit application was submitted pursuant to subparagraph (f)(3)(A)</td></tr>
<tr><td>Is listed in Table D-1 in Attachment D of this rule, for an owner or operator submitting a B-Plan or a B-Cap</td></tr>
<tr><td>An operator submitting a B-Cap that selects I-Plan Option 4</td><td>Is listed in Table D-2 in Attachment D of this rule, for an owner or operator submitting a B-Cap that selects I-Plan Option 4</td></tr>
<tr><td colspan="2">5 ppmv</td><td>Boiler with a Rated Heat Input Capacity less than 40 MMBtu/hour</td></tr>
<tr><td colspan="2">40 ppmv</td><td>Process Heater with a Rated Heat Input Capacity less than 40 MMBtu/hour with a representative NOx Concentration ≥ 75 ppmv provided operator achieves NOx Concentration within Phase I of an I-Plan and any additional reductions to meet the final NOx Concentration Limit are not used to meet Facility BARCT Target</td></tr>
<tr><td colspan="2">9 ppmv</td><td>Process Heaters with a Rated Heat Input Capacity of less than 40 MMBtu/hour with a Representative NOx Concentration less than 75 ppmv</td></tr>
</table>

Operators have the option to exclude Boilers and Process Heaters less than 40 MMBtu/hour from the I-Plan, B-Plan, and B-Cap. However, if an operator includes a Boiler or Process Heater less than 40 MMBtu/hour in the I-Plan, for most situations the NOx Concentration Limit for the Final

Phase BARCT Emission Target will be the final NOx Concentration limit of 5 ppmv for Boilers and 9 ppmv for Process Heaters. A provision was added for any Process Heater that is less than 40 MMBtu/hour with a high NOx concentration limit greater than 75 ppmv. Under this provision, the operator can use a NOx Concentration of 40 ppmv for the Final Phase BARCT Emission Target. Staff is aware of only one such Unit and this provision is designed to encourage the operator to reduce the NOx Concentration Limit in Phase I of the I-Plan.

Mass Emission Demonstration for an I-Plan with B-Plan or I-Plan with Table 1 or Table 2 – Paragraph (h)(5)

Paragraph (h)(5) establishes the requirements that an operator that elects to implement an I-Plan and a B-Plan, or an I-Plan to meet the NOx Limits in Table 1 and or Table 2 must demonstrate that the BARCT Equivalent Mass Emissions are less the Facility BARCT Emission Target for each phase of the I-Plan.

Mass Emission Demonstration for an I-Plan with B-Cap – Paragraph (h)(6)

Paragraph (h)(6) establishes the requirements that an operator that elects to implement an I-Plan and a B-Cap must demonstrate that the BARCT B-Cap Annual Emissions are less than the Facility BARCT Emission Target for each phase of the I-Plan.

Compliance with an I-Plan without a B-Plan or B-Cap – Paragraph (h)(7)

Paragraph (h)(7) establishes the requirements that an operator that elects to implement an I Plan without a B-Plan or B-Cap shall meet the NOx Concentration Limits and Corresponding CO Concentration Limits in Table 1 or Table 2 based on the schedule in the approved I-Plan.

Compliance with an I-Plan with B-Plan – Paragraph (h)(8)

Paragraph (h)(7) establishes the requirements that an operator that elects to implement an I-Plan and a B-Plan shall meet the Alternative BARCT NOx Concentration Limits in an approved B-Plan based on the schedule in the approved I-Plan.

Requirements for Implementing an I-Plan – Paragraph (h)(9)

Paragraph (h)(8) establishes the requirements for operators that are implementing an I-Plan with a B-Cap which includes the following:

- Meet the Alternative BARCT NOx Concentration Limits and decommission any Units in an approved B-Cap, and implement other emission reduction strategies to achieve the Facility BARCT Emission Target for each phase, based on the schedule in the approved I-Plan;
  Demonstrate daily compliance that mass emissions from all Units in the I-Plan are below the Facility BARCT Emission Target for each phase of the I-Plan, based on a 365-day rolling average as measured pursuant to subdivisions (k) or subparagraph (n)(2)(C), based on the applicable schedule in subparagraph (h)(8)(C) or (h)(8)(D);
- Meet the Phase I and Phase II Facility BARCT Emission Targets of I-Plan Option 3 for:
  - The Baseline Facility Emissions before January 1, 2031, only if the Facility is a Former RECLAIM Facility;
  - Phase I Facility BARCT Emission Target on and after January 1, 2031 and before January 1, 2035; and
  - Phase II Facility BARCT Emission Target on and after January 1, 2035; and

- Meet the Phase I, Phase II, and Phase III Facility BARCT Emission Targets of I-Plan Option 4 for:
    - The Baseline Facility Emissions before January 1, 2025, only if the Facility is a Former RECLAIM Facility;
    - Phase I Facility BARCT Emission Target on and after January 1, 2025 and before July 1, 2030;
    - Phase II Facility BARCT Emission Target on and after July 1, 2030 and before July 1, 2033; and
    - Phase III Facility BARCT Emission Target on and after July 1, 2033.

10 Percent Environmental Benefit for the B-Cap – Subparagraph (h)(4)

The South Coast AQMD has the obligation to ensure that PR 1109.1 can be approved by CARB and U.S. EPA to be incorporated into the State Implementation Plan (SIP). Staff has discussed the provisions of the B-Cap with both agencies, and they concur that the additional 10 percent reduction in the BARCT facility emission target is appropriate for the B-Cap. Since the B-Cap establishes a mass emissions cap compliance option, the Final Phase Facility BARCT Emission Target for the B-Cap is proposed to be reduced by an additional 10 percent. Based on discussions with U.S. EPA and review of U.S. EPA's January 2001 guidance for EIPs titled "Improving Air Quality with Economic Incentive Programs" the B-Cap is an Economic Incentive Program because it is both a source-specific cap and a trading EIP and does require an environmental benefit. U.S. EPA agrees that a 10 percent reduction in NOx is the most appropriate environmental benefit approach for the B-Cap. For additional details regarding the 10 percent environmental benefit, please refer to the Response to Comments.

Two Compliance Components of the B-Cap (Subparagraphs (h)(9)(A) and (h)(9)(B))

Under the B-Cap, there are two compliance components. The first component establishes and incorporates in a permit, the Alternative BARCT NOx Limit which will be based on the averaging time for the specific equipment category in Table 1 or Table 2. The second is the demonstration that actual mass emissions from all Units under the B-Cap are below the Facility BARCT Emission Target. Under the B-Cap, the BARCT Equivalent Mass Emissions, which is the sum of the emissions for each Unit emission reduction projects, including those to meet the Alternative BARCT NOx Limit, decommissioned Units, or other reduction strategies must be implemented for each phase of the I-Plan, and the operator must demonstrate that the NOx mass emissions for all Units in the I-Plan and B-Cap will be lower than the Facility BARCT Emission Target for each phase. Operators are required to conduct a daily 365-day demonstrations that the measured NOx emissions at the facility are below the Facility BARCT Emission Target for each phase of the I-Plan. Because this requirement is based on a 365-day average, a full year of data is needed to collect the first daily average. The effective date when an operator is required to demonstrate that the annual emissions are below the Facility BARCT Emission Target is 365 days after the B-Cap Effective Compliance Date of the Facility BARCT Emission Target in Table 6, however, the first day that used in the 365-day rolling average is the B-Cap Effective Compliance Date of the Facility BARCT Emission Target. The following provides the schedule of the effective dates for the two I-Plan options for operators with a B-Cap. These dates reflect first day in which daily demonstration is required to show that based on the 365-day rolling average, NOx mass emissions from all Units in the I-Plan and B-Cap are less than the Facility BARCT Emission Target for each phase of the I-Plan. Prior to implementation of the first phase, operators will be subject to the Baseline Facility Emissions upon exiting RECLAIM. Operators will not be subject to the Facility BARCT Emission Target for Phase I, Phase II, and if applicable Phase III until the facility exits RECLAIM and becomes a former RECLAIM facility.

Table 2.4-9: Compliance Demonstration Dates for the Facility BARCT Emission Target for I-Plans and B-Cap

I-Plan Option	Baseline Facility Emissions	Phase I	Phase II	Phase III
I-Plan Option 3	Before January 1, 2021, only if Facility is a Former RECLAIM Facility	On and after January 1, 2031 and before January 1, 2035	On and after January 1, 2035	Not Applicable
I-Plan Option 4	January 1, 2025, only if the Facility is a Former RECLAIM Facility	On and after January 1, 2025 and before July 1, 2030	On and after July 1, 2030 and before July 1, 2033	On and after July 1, 2033

Subdivision (i) – I-Plan, B-Plan, and B-Cap Submittal and Approval Requirements

I-Plan, B-Plan, and B-Cap Submittal and Approval Requirements

This subdivision specifies the submittal, and review and approval requirements for the I-Plan, B-Plan, and B-Cap. Submittal requirements for the I-Plan, B-Plan, and B-Cap are provided in paragraphs (i)(1), (i)(2), and (i)(3), respectively.

B-Plan and B-Cap Submittal – Paragraphs I-Plan Submittal Requirements – paragraph (i)(1)

This paragraph includes the submittal requirements for facilities complying with an alternative schedule in the I-Plan. On or before September 1, 2022 a facility may elect to submit an I-Plan identifying which units will be part of the plan and I-Plan option selected.

For many units, the Unit BARCT B-Cap Emissions will be lower than the BARCT Equivalent Mass Emissions for individual Units since compliance demonstration for the mass emissions cap for the B-Cap is based on a 365-day average as compared to shorter averaging times required for the Alternative NOx BARCT Emission Limits which are largely based on Table 1. PR 1109.1. This provision requires operators to provide an explanation when there is this differential. Acceptable reasons can be the averaging time, built-in compliance margin for Alternative BARCT NOx Limit, changes in capacity or use of the Unit, or any other emission reduction strategy.

B-Plan and B-Cap Submittal Requirements – paragraphs (i)(2) and (i)(3)

Submitted B-Plan and B-Cap must meet specific criteria to be considered complete:

- The device identification number and description,
- Alternative BARCT NOx limits for each unit that will cumulatively meet the Facility BARCT Emission Target

ALTERNATIVE BARCT NOx LIMIT FOR PHASE I, PHASE II, OR PHASE III is the unit specific NOx concentration limit that is selected by the owner or operator to achieve the Phase I, Phase II, or Phase III Facility BARCT Emission Target in the aggregate in the B-Plan or B-Cap, where the NOx concentration limit will include the corresponding percent O_2 correction and determined based on the averaging time in Table 1 or subdivision (k), whichever is applicable.

PHASE I, PHASE III, OR PHASE III BARCT B-CAP ANNUAL EMISSIONS means the total NOx mass emissions remaining per Facility that incorporates BARCT Alternative NOx Limits for Phase I, Phase II, and Phase III, decommissioned units, and other emission reduction strategies to meet the respective Phase I, Phase II, or Phase III Facility BARCT Emission Targets in an I-Plan and are calculated pursuant to Attachment B of this rule.

PHASE I, PHASE II, OR PHASE III BARCT EQUIVALENT MASS EMISSIONS means the total NOx mass emissions remaining per Facility that incorporates respective BARCT Alternative NOx Limits for Phase I, Phase II, and Phase III in an approved B-Plan that are designed to meet the respective Phase I, Phase II, or Phase III Facility BARCT Emission Targets in an I-Plan and are calculated pursuant to Attachment B of this rule.

For the purpose of B-Plan, the Alternative BARCT NOx limits is the concentration limit determined by the facility for each of the included units in the plan in a manner that the facility achieves the Facility BARCT Emission Target in aggregate. For the purpose of B-Cap, the Alternative BARCT NOx limits combined with other emission reduction strategies are used to determine the BARCT B-Cap Annual emissions.

For a B-Plan, the operator must demonstrate that the Phase I, Phase II, and Phase III BARCT Equivalent Mass Emissions is equal to or less than the respective Phase, I, Phase II, and Phase III Facility BARCT Emission Target. The BARCT Equivalent Mass Emissions for each facility is the total mass emissions at full implementation of control projects and must be calculated based on the Alternative BARCT NOx limits using the equations in Attachment B in PR 1109.1 and using the NOx Concentration Limit listed in "Baseline NOx Emissions and Representative for Facilities Regulated Under Rule 1109.1 - Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations".

For a B-Cap, the operator must demonstrate that the Phase I, Phase II, and Phase III BARCT B-Cap Annual Emissions is equal to or less than the respective Phase, I, Phase II, and Phase III Facility BARCT Emission Target. The BARCT B-Cap Annual Emissions for each facility is the total mass emissions at full implementation of control projects and must be calculated based on the Alternative BARCT NOx limits and other emission reduction strategies as shown in Attachment B in PR 1109.1. Under a B-Cap, an owner or operator must achieve Alternative NOx Limits as well as demonstrate that the actual facility-wide emissions for all units in the B-Cap are at or below the Facility BARCT Emission Target. The unit specific emission limit is based on the averaging time specified in Table 1 for the applicable unit, however, the on-going compliance demonstration of facility-wide mass emissions are based on a rolling 365-day average, each day.

PHASE I, PHASE II, OR PHASE III FACILITY BARCT EMISSION TARGET means the total NOx mass emissions per Facility that must be achieved in an approved B-Plan or B-Cap that are based the percent reduction target of Phase I, Phase II, or if applicable, Phase III of an I-Plan option in Table 6 and are calculated pursuant to Attachment B of this rule.

Also, the owner or operator is required to demonstrate compliance with the previously approved I-Plan through using the equation specified under Attachment B of PR 1109.1 to show that the percent of emission reduction from either B-Plan or B-Cap is equal or more than the I-Plan Percent Reduction Targets for each phase per PR 1109.1 Table 4.

I-Plan, B-Plan, and B-Cap Review and Approval Process – Paragraph (i)(4)

Paragraph (i)(4) provides the criteria for evaluating the I-Plan, B-Plan, and B-Cap. The Executive Officer will notify the owner or operator if the submitted plan is approved or disapproved. Approval will be based on the criteria set forth in paragraph (i)(4). The I-Plan, B-Plan, and B-Cap are subject to disapproval if any of the criteria are not met. Each of the criteria is described below.

Timely Complete Submittal of an I-Plan, B-Plan, or B-Cap – Paragraph (i)(4)(A)

The completed plans must be submitted on or before September 1, 2022 and must include all information that is required to be submitted under subparagraphs (i)(1), (i)(2) and (i)(3). The Executive Officer will review this information to ensure it meets the submittal requirements, is complete, and accurate.

Identification of Units in the I-Plan, B-Plan, or B-Cap – Subparagraph (i)(4)(B)

The plans should be limited to units that qualify for the respective plan pursuant to subparagraph (h)(1)(B) and are located at the same facility or facilities with the same ownership. Subparagraph (h)(1)(B) either directly specifies or references the Units that must be included, optional, and Units that must be excluded for the various plans. Operators have the option to submit a plan for a single Facility or Facilities With The Same Ownership. The operator must provide the device and device identification number for each Unit for each Facility or Facility With the Same Ownership.

Selecting an I-Plan Option – Subparagraph (i)(4)(C)

The operator must provide the I-Plan option selected. Selection of any I-Plan option must meet the requirements specified in paragraph (h)(2).

Baseline NOx Emissions and Representative NOx Concentrations - (i)(4)(D)

All calculations must use the Baseline NOx Emissions and Representative NOx Concentrations that were established through the process provided under paragraph (h)(3). A B-Plan, B-Cap, or I-Plan will not be approved if an operator uses Baseline NOx Emissions or Representative NOx Concentrations for any unit that are not in the approved "Baseline NOx Emissions and Representative NOx Concentrations for Facilities Regulated Under Rule 1109.1 Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations," or that meet the conditions for using a different value as allowed under paragraph (h)(3).

BARCT Equivalent Mass Emissions and Alternative BARCT NOx Limit (i)(4)(E)

The operator must demonstrate that the BARCT Equivalent Mass Emissions were calculated pursuant to Attachment B, and the use of Alternative BARCT NOx Limits selected when calculating the BARCT Equivalent Mass Emissions meets the requirements specified under subparagraph (g)(1)(C) for the B-Plan and subparagraph (g)(2)(C) for a B-Cap. The requirements under these referenced subparagraphs have limitations on the maximum concentration limit that can be selected for an Alternative NOx Limit and references requirements for Conditional NOx Concentration Limits that also has specific requirements regarding submitting a permit application and the maximum NOx Concentration Limit that can be used for the Alternative NOx Limit. For any Unit where an Alternative NOx Limit is not specified for a given phase, the operator must use the Representative NOx Concentration, which will equate to the Baseline NOx Emissions. All of these provisions must be satisfied for approval of an I-Plan, B-Plan, and B-Cap.

Facility BARCT Emission Target – Subparagraph (i)(4)(F)

One of the key elements of the I-Plan are establishing the Facility BARCT Emission Targets. The Facility BARCT Emission Targets are based on the Percent Reduction Targets for each phase that are applied to the overall NOx reductions and must be calculated for each phase pursuant to Attachment B of PR 1109.1. The total NOx reductions are based on the Final Phase BARCT Emission Target. The operator is required to only use NOx concentration limits for each unit pursuant to paragraph (h)(4), which specifies under what situations a Unit can use the Table 1 or Table 2 conditional NOx Concentration Limit. Part of the eligibility for using a Table 2 conditional NOx Concentration Limit is that the permit application was submitted on or before June 1, 2022. If an incorrect NOx concentration limit is used to calculate the Final Phase BARCT Emission Target, the I-Plan, B-Plan, or B-Cap would be disapproved.

Demonstration that BARCT Equivalent Mass Emissions are Less than the Facility BARCT Emission Target (B-Plan) – Subparagraph (i)(4)(G)

This provision is critical for approving an I-Plan that is using a B-Plan, or an I-Plan where an operator is meeting the Table 1 or Table 2 NOx Concentration Limits. Operators must demonstrate that the BARCT Equivalent Mass Emissions are below the Facility BARCT Emission Targets for each phase when taking into account the application of Alternative NOx Concentration Limits for each phase of the I-Plan. For the B-Plan, this review ensures that the Facility BARCT Emission Target is met based on the Alternative BARCT NOx limits that the operator identified for units under the B-Plan. The submitted B-Plan must demonstrate Equivalent Mass Emissions for units to cumulatively meet the Facility BARCT Emission Target that is adjusted by the Percent Reduction Targets based on the selected I-Plan option and the applicable Implementation Schedule in PR 1109.1 Table 6, using the calculation method provided in PR 1109.1 Attachment B. This demonstration is required to approve the I-Plan and B-Plan, or of the I-Plan or B-Plan is modified.

Demonstration that BARCT B-Cap Annual Emissions are less than the Facility BARCT Emission Target (B-Cap) – Subparagraph (i)(4)(H)

For the B-Cap, the review ensures the BARCT B-Cap Annual Emissions are less than the Facility BARCT Emission Target, where BARCT B-Cap Annual Emissions can account for emission reductions associated with implementation of Alternative BARCT NOx limits, units that the operator has identified to be decommissioned, and other reductions. The operator is required to provide an explanation when the Unit BARCT B-Cap Annual Emissions are less than the BARCT B-Cap Annual Emissions. The operator must provide sufficient details to describe the differential to ensure the differential is reasonable taking into consideration information such as the type of Unit, anticipated future usage of the Unit, and current and future capacity of Unit, use of the Unit within existing and future operations, anticipated compliance margins, increased efficiency, etc. The submitted B-Cap must be prepared using the calculation method provided in PR 1109.1 Attachment B to demonstrate that Equivalent Mass Emissions for included units cumulatively meets the Facility BARCT Emission Target less 10 percent of the overall reductions required and then adjusted by the Percent Reduction Targets based on the selected I-Plan option and the applicable Implementation Schedule in PR 1109.1 Table 6.

Disapproval of an I-Plan, B-Plan, and B-Cap – Paragraphs (i)(5) and (i)(6)

If Executive Officer disapproves the initial I-Plan, B-Plan or B-Cap, the proposed rule considers a 45-day period for the owner or operator to resubmit a corrected plan. Upon re-submittal, the I-Plan, B-Plan, or B-Cap will be reviewed and approved if the criteria set forth in paragraph (i)(4) is met. If the applicable criteria are not met or there are deficiencies, the I-Plan, B-Plan, or B-Cap will be disapproved. Upon second disapproval of the plan by the Executive Officer, the owner or operator must comply with the emission limits in Table 1 or Table 2 of PR 1109.1 pursuant to the compliance schedule in the selected I-Plan option. An operator who is required to meet the compliance schedule under paragraph (e)(1), is not precluded from meeting NOx and CO Concentration Limits in Table 2, provided the requirements under paragraph (d)(6) for the conditional NOx and CO Concentration Limits were met.

Modification to an Approved I-Plan, Approved B-Plan, or Approved B-Cap – Paragraph (i)(7) and (i)(8)

Paragraph (i)(7) includes the procedure the facilities must follow to apply for a modification to their approved I-Plan, B-Plan or B-Cap. In addition, PR 1109.1 includes requirements for when an I-Plan, B-Plan and B-Cap shall be modified:

- A unit identified as meeting Table 2 no longer meets the requirements of subparagraph (d)(2)(A) or (d)(2)(B);
- A unit in an approved B-Cap or B-Plan, identified as meeting Table 2 for establishing the Phase I, Phase II, or Phase III BARCT Facility Emission Target, is decommissioned;
- A higher Alternative BARCT NOx Limit will be proposed in the South Coast AQMD permit application than the Alternative BARCT NOx Limit for that unit in the currently approved I-Plan, B-Plan, or B-Cap;
- Any emission reduction project is moved to a later implementation phase, any emission reduction project is moved between phases, or any emission reduction project is removed from a phase;
- The owner or operator receives written notification from the Executive Officer that modifications to the I-Plan, B-Plan, or B-Cap are needed; or
- A permit application is submitted for a New Unit that meets at least one provision of subparagraph (g)(2)(J).

Review and approval of modifications to an I-Plan, B-Plan, or B-Cap shall be based the initial review and approval process. Although there is no specified timeframe to submit a modification, the owner or operator is expected to submit a modification upon knowing one of the items under paragraph (i)(5) are triggered.

Notification of Pending Approval of an I-Plan, B-Plan, or B-Cap – Paragraph (i)(9)

PR 1109.1 requires the Executive Officer to make the I-Plan, B-Plan, or B-Cap or modifications to an approved I-Plan, B-Plan, or B-Cap available to the public on the South Coast AQMD website 30 days prior to approval. Purpose of this provision is to provide an opportunity for the public to view the I-Plan, B-Plan, or B-Cap prior to approval.

Subdivision (j) – Time Extension

PR 1109.1 allows two primary types of time extensions: one for specific circumstances outside of the control of the owner or operator, and the second aims to address situations where an emission reduction project falls outside of a turnaround window due to the permitting process. This subdivision establishes the criteria for time extensions, information that must be submitted, and the approval process.

Under paragraph (j)(1), an operator may request one 12-month extension for each unit for specific circumstances outside the control of the owner or operator. The operator should provide sufficient detail to explain the amount of time up to 12 months that is needed to complete the emission reduction project. If the operator requests less than 12 months, the Executive Officer will accept a subsequent request provided the total time for previous extensions plus subsequent requests does not exceed 12 months. Such a request must be made in writing no later than 90 days prior to the compliance schedule specified in the approved I-Plan. The owner or operator must demonstrate that there are specific circumstances that necessitate the additional time requested to complete the emission reduction project. The operator must provide sufficient information to document the operator took the necessary steps to ensure the project would not be delayed with a description and documentation of why the project was delayed. PR 1109.1 establishes four main areas that will be evaluated: Delays related to missed milestones; delays due to other agency approvals; delays related to delivery of parts or equipment; and delays related to workers or services. More specifically, as required under subparagraph (j)(6)(C), information or documentation as to why there was a delay of key schedules, reasons for another agency's delay, purchase orders and invoices from vendors, as well as an explanation of the delay and additional time for contract workers and source testers.

For the second type of time extension, the amount of time allowed will be based on when the Permit to Construct was issued and the subsequent turnaround for the specific unit. An operator that requests a time extension for a turnaround under paragraph (j)(2) can also request a time extension under subparagraph (j)(1), provided the operator meets the criteria under that paragraph. The criteria for an extension for a turnaround are more specific and the operator must provide in writing at the time the permit application is submitted, the months and year(s) of the turnaround and the years for the subsequent turnaround. The Executive Officer will determine the time extension based on the current turnaround and the subsequent turnaround schedule. Other criteria are needed to ensure that in order to receive the extension, the issuance of the Permit to Construct does not align with the turnaround window because of the amount of time between the permit application submittal and issuance of the Permit to Construct. Approval of a time extension for a turnaround is based on the criteria set forth under subparagraph (j)(2)(C). Staff will assess the information and work with the operator to establish the appropriate timeframe of the extension taking into account the current turnaround and the subsequent turnaround.

Paragraph (j)(4) provides the required timeframes for a Facility to submit the written request for approval of a time extension and paragraph (j)(5) lists the specific information required such as the affected unit in which phase, the amount of extension time being requested, as well as the month and year of the turnaround if that is a reasoning for the extension.

If there is additional information needed to substantiate the request for a time extension, the Executive Officer may request additional information. This provision is to allow the operator the opportunity to provide critical information needed to approve a time request. If the Executive Officer requests additional information, the operator must provide that information based on the timeframe specified by the Executive Officer. Approval of the time extension represents an amendment to the approved I-Plan, and the operators must adhere to the timeframe established in the approved time extension to meet the NOx and CO emission limit in PR 1109.1 Table 1, PR 1109.1 Table 2, approved B-Plan, or approved B-Cap. If the Executive Officer disapproves the time extension request, the applicable emission limits must be met within 60 calendar days after notification of disapproval is received.

Facilities implementing a B-Cap (paragraph (j)(3)) may request a time extension provided a Permit to Construct was issued more than 18 months after the permit application was submitted. This provides additional time when the project was delayed due to the delay in receiving a Permit to Construct. The extension is limited to no longer than the time difference between 18 months after the complete permit applications was submitted and when the Permit to Construct was issued. Paragraph (j)(3) allows a facility with a B-Cap to request for an extension of the dates to meet the Facility BARCT Emission Target for reasons provided under paragraphs (j)(1) and (j)(2) discussed above

Paragraph (j)(4) provides the required timeframes for a Facility to submit the written request for approval of a time extension. Time extensions must be submitted no later than 180 days prior to a Compliance Date in paragraph (f)(1) or an approved I-Plan or 180 days prior to the effective date of the Facility BARCT Emission Target. This allows sufficient time for the extension to be evaluated.

Paragraph (j)(5) lists the specific information required such as the affected unit in which phase, the amount of extension time being requested, as well as the month and year of the turnaround if that is a reasoning for the extension. The time extension request shall include information needed to identify the Unit, time requested, and the reason for the extension under paragraph (j)(8). The Executive Officer will review the request based on information on key construction milestones missed, delays from agency review, delays related to the delivery of parts, or delays related to service providers for an extension related to circumstances beyond the control of the facility. For those related to a delay in receiving a Permit to Construct, dates when the application was submitted and when the Permit to Construct was issued. The length of the extension is determined based on limitations in paragraphs (j)(1) through (j)(3). An owner that receives an extension pursuant to paragraphs (j)(1) or (j)(2) shall meet the limits within the time frame in the approval. For an extension pursuant to paragraph (j)(3), the Facility BARCT Emission Target will be adjusted for each Unit where a time extension was approved.

Under paragraph (j)(10), for facilities under a B-Cap, time extensions to comply with the Facility BARCT Emission Target for individual unit projects will require an adjustment to the Facility BARCT Emission Target to ensure the facility continues to comply with B-Cap. Such an adjustment to the Facility BARCT Emission Target would be based on the reductions not yet achieved within the target due to time extension provided to that unit or units. Thus, until the unit reduces emissions as scheduled in the B-Cap, the Facility BARCT Emission Target would need to be temporarily increased. That increase would be based on the unit's emission levels from the previous phase, or if in Phase I, from the Baseline Unit Emissions. When the time extension expires, the unit should be achieving reduced emissions and the Facility BARCT Emission Target can reduced to the original levels as required by the I-Plan. The duration of the time extensions is provided in paragraph (j)(7).

Subdivisions (k) – CEMS REQUIREMENTS

This subdivision contains the CEMS requirements for the combustion equipment subject to PR 1109.1.

Units Requiring CEMS – Paragraphs (k)(1) through (k)(3)

For any unit that has a CEMS, or the owner or operator elects to use a CEMS to demonstrate compliance with the applicable PR 1109.1 NOx and Corresponding CO Concentration Limits, the installation and operation of CEMS must be in compliance with the applicable requirements of

Rule 218.2 – Continuous Emission Monitoring System: General Provisions and Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications when it becomes a Former RECLAIM Facility. Units with a Rated Heat Input Capacity of greater than or equal to 40 MMBtu/hour and Sulfuric Acid Furnaces at Former RECLAIM Facilities are required to have NOx CEMS. Additionally, Sulfuric Acid Furnaces at Former RECLAIM Facilities are required to have an oxygen CEMS within 12 months of rule adoption. Units at a Former RECLAIM Facility with a CO CEMS on the date of rule adoption must continue to operate and maintain the CO CEMS pursuant to Rules 218.2 and 218.3 to demonstrate compliance with the applicable PR 1109.1 CO limits. PR 1109.1 requires these CO CEMS be certified within 12 months of rule adoption. Until that time, facilities will continue to be subject to Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions.

Invalid CEMS Data – Paragraph (k)(4)

Invalid data shall be excluded pursuant to Rule 2012 while the facility remains in RECLAIM and then excluded pursuant to Rules 218.2 and 218.3 once the facility becomes a Former RECLAIM Facility.

Missing Data Procedures – Paragraph (k)(5)

For Facilities with an approved B-Cap with a certified CEMS that is not collecting data, the missing data calculation is based on the length of the missing data period. If the missing data period is less than 8 hours, the missing data shall be calculated using the hourly data immediately before and after the missing period. If the missing data period is more than 8 hours, the missing data shall be calculated using the maximum hourly data from the past 30 days; the 30 days begins on the day immediately before the day of the missing data occurred. It is assumed that shorter missing data periods would be similar to the most recent operational data. However, that assumption is no longer as likely during long outages and thus the worst case will be attributed to the missing data period. Missing data is only applicable to facilities utilizing a B-Cap.

Subdivisions (l) – Source Test Requirements

This subdivision contains the source testing requirements for the combustion equipment subject to PR 1109.1.

Requirements for Source Testing – Paragraph (l)(1)

For any Unit without CEMS, compliance with the applicable PR 1109.1 NOx and Corresponding CO Concentration Limits and percent of oxygen must be demonstrated by conducting a source test according to PR 1109.1 Table 7 or Table 8. The source test subdivision has two compliance schedules, subparagraph (l)(1)(A) for Units with no ammonia in the exhaust (e.g., units without SCR) and subparagraph (l)(1)(B) for Units with ammonia in the exhaust. This paragraph also includes the required averaging time for Units that are required to demonstrate compliance with PR 1109.1 concentration limits based on a source test; all Units that are not required to install and maintain CEMs must demonstrate compliance based on a source test protocol with an averaging time duration between 60 to 120 minutes.

PR 1109.1 subparagraph (l)(1)(A) requires Units that do not require CEMS and do not vent to air pollution control equipment with ammonia injection to demonstrate compliance with the PR 1109.1 NOx and CO Concentration Limits pursuant to the source test schedule in Table 7. For an owner or operator of a Unit not required to install and operate a CEMS that vents to air pollution control equipment with ammonia injection, paragraph (l)(1)(B) requires compliance with the PR 1109.1 NOx and CO Concentration Limits and the established ammonia South Coast AQMD permit limit (permit limit) to be demonstrated according to the source test schedule in Table 8. The source test schedules in Tables 7 or Table 8 vary depending on the which CEMS the Facility has for the different pollutants being measured (e.g., NOx, CO, or ammonia). When more than one pollutant requires source testing, Tables 7 and 8 require simultaneous source testing. Conducting a NOx, CO, and ammonia source test simultaneously is important as the pollutants have an inverse relationship and it is critical that all pollutants are meeting the limits.

Source Test Schedule for Units Without Ammonia Injection – PR 1109.1 Table 7

The table below has the source test schedules for Units with ammonia emissions in the exhaust. The source test schedule for these Units is divided into two categories dependent on combustion equipment: 1.) Vapor Incinerators less than 40 MMBtu/hr and Flares; and 2.) all other Units. These two categories are further divided, dependent on what type of CEMS the Unit has: A.) Units operating without NOx or CO CEMS, B.) Units operating with NOx CEMS and without CO CEMS, and C.) Units operating without NOx CEMS and with CO CEMS. Vapor incinerators typically operate intermittently and are overall low emitters so source testing every 3 years is a reasonable check on their performance. Other units, such as boilers and heaters <40 MMBTU/hr, operate more frequently so have higher emission potential thus, more source testing on an annual basis.

Source Test Schedule for Units with Ammonia Injection – PR 1109.1 Table 8

The table below has the source test schedules for Units with ammonia emissions in the exhaust. The source test schedule for these Units is divided into five categories dependent on what type of CEMS the Unit has: A.) Units operating without NOx, CO, or ammonia CEMS, B.) Units operating with NOx CEMS and without CO or ammonia CEMS, C.) Units operating with NOx and CO CEMS and without ammonia CEMS, D) Units operating with NOx and ammonia CEMS and without CO CEMS, E) Units operating with ammonia CEMS and without NOx or CO CEMS, F) Units operating with ammonia and CO CEMS and without NOx CEMS, and G) Units operating with CO CEMS and without a NOx or ammonia CEMS. Tests are initiated within 12 months after compliance with applicable NOx and CO concentration limits, and, if applicable an ammonia permit limits, and annually afterwards for those pollutants not monitored with a CEMS. If the annual tests exceed the concentration limits, then four consecutive quarterly tests are required to demonstrate compliance before resuming the annual testing schedule.

Table 2.4-10: PR 1109.1 Table 7 – Source Testing Schedule for Units without Ammonia Emissions in the Exhaust

CEMS Status	Source Test Schedule
Vapor Incinerators <40 MMBtu/hr and Flares	
Units Operating without NOx and CO CEMS	• Conduct simultaneous source tests for NOx and CO within 12 months of being subject to applicable NOx and CO concentration limits and every 36 months thereafter

CEMS Status	**Source Test Schedule**
Units Operating with NOx CEMS and without CO CEMS	• Conduct a source test for CO within 12 months of being subject to applicable NOx and CO concentration limits and every 36 months thereafter
Units Operating without a NOx CEMS and with a CO CEMS	• Conduct a source test for NOx within 12 months of being subject to applicable NOx and CO concentration limits and every 36 months thereafter
All Other Units	
Units Operating without NOx and CO CEMS	• Conduct simultaneous source tests for NOx and CO quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx and CO concentration limits • If an annual source test demonstrates an exceedance of applicable NOx or CO concentration limit, four consecutive quarterly source tests must demonstrate compliance with the applicable NOx and CO concentration limits prior to resuming annual source tests
Units Operating with NOx CEMS and without CO CEMS	• Conduct a source test for CO within 12 months of being subject to applicable NOx and CO concentration limits and annually thereafter

CEMS Status	Source Test Schedule
Units Operating without NOx CEMS and with CO CEMS	• Conduct a source test for NOx quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx concentration limit • If an annual source test demonstrates an exceedance of a NOx concentration limit, four consecutive quarterly source tests must demonstrate compliance with the NOx concentration limit prior to resuming annual source tests

Table 2.4-11: PR 1109.1 Table 8 – Source Testing Schedule for Units with Ammonia Emissions in the Exhaust

CEMS Status	Source Test Schedule
Units Operating without NOx, CO, and Ammonia CEMS	• Conduct simultaneous source tests for NOx, CO, and ammonia quarterly during the first 12 months of being subject to applicable NOx concentration and CO concentration limit • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx and CO concentration limits, and ammonia permit limit • If an annual source test demonstrates an exceedance with the NOx concentration limit, CO concentration limit, or ammonia permit limit, four consecutive quarterly source tests must demonstrate compliance with the applicable NOx and CO concentration limits, and ammonia permit limit prior to resuming annual source tests

CEMS Status	Source Test Schedule
Units Operating with NOx CEMS and without CO and Ammonia CEMS	• Conduct simultaneous source tests for CO and ammonia quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits, if four consecutive quarterly source tests demonstrate compliance with the CO concentration limit and ammonia permit limit • If an annual source test demonstrates an exceedance with a CO concentration limit or ammonia permit limit, four consecutive quarterly source tests must demonstrate compliance with the CO concentration limit and ammonia permit limit prior to resuming annual source tests
Units Operating with NOx and CO CEMS and without Ammonia CEMS	• Conduct a source test for ammonia quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the ammonia permit limit • If an annual source test demonstrates an exceedance with the ammonia permit limit, four consecutive quarterly source tests must demonstrate compliance with the ammonia permit prior to resuming annual source tests
Units Operating with NOx and Ammonia CEMS and without CO CEMS	• Conduct a source test for CO within 12 months of being subject to applicable NOx and CO concentration limits and annually thereafter

CEMS Status	**Source Test Schedule**
Units Operating with Ammonia CEMS and without NOx and CO CEMS	• Conduct simultaneous source tests for NOx and CO quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx and CO concentration limits • If an annual source test demonstrates an exceedance of applicable NOx concentration limit or CO concentration limit, four consecutive quarterly source tests must demonstrate compliance with the NOx and CO concentration limits prior to resuming annual source tests
Units Operating with CO and Ammonia CEMS and without NOx CEMS	• Conduct a source test for NOx quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx concentration limit • If an annual source test demonstrates an exceedance with the NOx concentration limit, four consecutive quarterly source tests must demonstrate compliance with the applicable NOx concentration limit prior to resuming annual source tests

CEMS Status	Source Test Schedule
Units Operating with CO CEMS and without NOx and Ammonia CEMS	• Conduct simultaneous source tests for NOx and ammonia quarterly during the first 12 months of being subject to applicable NOx and CO concentration limits • Source tests may be conducted annually after the first 12 months of being subject to applicable NOx and CO concentration limits if four consecutive quarterly source tests demonstrate compliance with the applicable NOx concentration limit and ammonia permit limit • If an annual source test demonstrates an exceedance of applicable NOx concentration limit or ammonia permit limit, four consecutive quarterly source tests must demonstrate compliance with the NOx concentration and ammonia permit limit limits prior to resuming annual source tests

Annual Source Test – Paragraph (l)(2)

The annual source test must be conducted every calendar year, but not sooner than six months from the previous source test. If the Unit has not operated for at least six consecutive calendar months, the annual source test is due no later than 90 days after the date of resumed operation and the owner or operator must demonstrate that the Unit has not been operated by using a non-resettable fuel meter to maintaining monthly fuel usage records.

CEMS In Lieu of Source Testing – Paragraph (l)(3)

This provision clarified that if an owner or operator elects to operate a CEMS in lieu of conducing source testing, the CEMS needs to meet the requirements in subdivision (k).

Initial Compliance Demonstration for New or Modified Units – Paragraph (l)(4)

The PR 1109.1 requirement for initial compliance demonstration of a new or modified unit is dependent on the averaging time of the Unit. Units with an averaging time less than 120 minutes are required to conduct an initial source test within six months from commencing operation and afterward, pursuant to the applicable schedule in PR 1109.1 Table 7 or Table 8. Units with an averaging time greater than 120 minutes as required by Table 1 or Table and Units required to adjust the NOx span range are required to demonstrate initial compliance through maintaining and operating a certified CEMS.

Submitting a Source Test Protocol and Timing of Source Test – Paragraph (l)(5)

PR 1109.1 requires the owner or operator to submit the complete source test protocol, that includes an averaging time of no less than 60 minutes but no longer than 120 minutes, to the South Coast AQMD Executive Officer for approval at least 60 days prior to conducting the source test, unless otherwise approved by the Executive Officer. The source test must be conducted within 90 days after the source test protocol has been approved by the Executive Office. A complete source test protocol should contain, but not limited to, reason for the source test, Permit to Construct or Permit to Operate, process description, sampling and analytical methods, process schematics, sampling location and related dimensions, and quality assurance procedures.

Source Test Notification – Paragraph (l)(6)

The owner or operator must notify the Executive Officer of the source test date at least one week prior to conducting the source test by calling 1-800-CUT-SMOG. The notification shall include facility name and identification number, device identification number, and the source test date.

Subsequent Source Test Protocols – Paragraph (l)(7)

Any source test conducted after the approval of the initial source test protocol does not require another approved source test, unless requested by the Executive Officer, if the method of operation of the Unit has not changed in a manner which would require a permit update, the proposed rule or permit concentration limits have not become more stringent, the referenced source test method(s) has not changed, and the approved source test protocol is representative of the Unit's operation and configuration, unless requested by the Executive Officer.

Conducting the Source Test – Paragraph (l)(8)

Upon approval of the source test protocol, the source test must be conducted using a South Coast AQMD approved contractor under the Laboratory Approval Program, during normal operating conditions and not during startup and shutdown, and using the applicable test methods:

- South Coast AQMD Source Test Method 100.1 – Instrumental Analyzer Procedures for Continuous Gaseous Emission Sampling; or
- South Coast AQMD Source Test Method 7.1 – Determination of Nitrogen Oxide Emissions from Stationary Sources and South Coast AQMD Source Test Method 10.1 – Carbon Monoxide and Carbon Dioxide by Gas Chromatograph/Non-Dispersive Infrared Detector (GC/NDIR) – Oxygen by Gas Chromatograph-Thermal Conductivity (GC/TCD);
- South Coast AQMD Source Test Method 207.1 – Determination of Ammonia Emissions from Stationary Sources; or
- Any other test method determined to be equivalent and approved by the Executive Officer, and either the California Air Resources Board or the U. S. Environmental Protection Agency, as applicable.

Vapor Incinerators – Paragraph (l)(9)

For Vapor Incinerators, demonstration that the Unit meets the applicable NOx Concentration Limit may be based on the NOx emission from only the burner and does not need to include the waste stream being directed to the Unit.

Source Test Reports – Paragraph (l)(10)

Source test reports shall be submitted to the Executive Officer within 90 days of the completed source test and shall include the source test results and the Unit's description.

Source Test Reports – Paragraphs (l)(11) and (l)(12)

If a source test demonstrates that a PR 1109.1 limit has been exceeded, that exceedance is considered a violation or PR 1109.1 and the owner or operator shall inform the Executive Officer within 72 hours of knowledge or when the owner or operator should have reasonably known of the exceedance.

Subdivision (m) – Diagnostic Emission Checks

This subdivision contains the requirements for diagnostic emission checks which is required for any unit performing a source test every 36 months. The provisions provide the protocol to conduct the 30-minute diagnostic checks and the applicable schedule based on the corresponding source test schedule provided in this subdivision.

If emissions are measured in excess of an applicable PR 1109.1 emission limit or a permit condition using a diagnostic emissions check, this would not be considered a violation if an owner or operator corrects the problem and demonstrates compliance with the proposed rule using another diagnostic emissions check within 72 hours from the time they knew of excess emissions or shut down the unit by the end of an operating cycle.

Subdivision (n) – Monitoring, Recordkeeping, and Reporting Requirements

This subdivision contains the provisions for monitoring and recordkeeping for CEMS and source test records; diagnostic emission checks; startup and shutdown logs; the details of interest from either of the activity logs; and the required sequence of recordkeeping and reporting.

Facilities that utilize a B-Cap shall report daily facility-wide emissions based on CEMS data on a monthly basis. For units that do no utilize a CEMS, daily emissions shall be determined by use an enforceable method approved by the Executive Officer, such as source test results and non-resettable totalizing fuel or time meter. Additionally, daily records for units included in an approved B-Cap shall include emissions during startups, shutdowns, maintenance, and times where the CEMS data was missing or invalid. This data shall be used on a daily basis to demonstrate compliance with the B-Cap. This subdivision has a reporting provision for the owner or operator of boilers and process heaters included in a B-Plan that will meet either the Interim NOx and CO Concentration Limits in Table 4 of PR 1109.1 or the Interim NOx concentration limit of 0.03 lb/MMBtu based on a daily rolling 365-day average upon exiting RECLAIM.

Units which are exempted from compliance with NOx and CO emission limits per PR 1109.1 are required to conduct monitoring, recordkeeping and reporting and the corresponding provisions (method and schedule) are included in this subdivision.

The owner or operator of a boiler or process heater less than 40 MMBtu/hour or a unit complying with a conditional limit in PR 1109.1 Table 2 is required to maintain records of burner replacement, including number of burners and date of installation. Recordkeeping will ensure compliance with the requirement that the owner or operator of a unit complying with a conditional limit in PR 1109.1 Table 2 must meet Table 1 emission limits upon replacement of the post-combustion equipment. Subdivision (m) includes provision requiring the owner to maintain records of the dates the existing post-combustion control equipment was installed or replaced.

Vapor incinerators utilizing the exemption in paragraph (o)(9) what keep records of annual throughput and emissions.

Burner replacement, including date of replacement and number of burners, shall be recorded to confirm compliance the compliance schedule in paragraph (f)(2) that is triggered when 50 percent or more of the burners or 50 percent of the heat input is replaced.

Likewise, dates of installation or replacement of post-combustion air pollution control equipment shall be recorded to demonstrate compliance with subparagraph (f)(4)(A).

Monitoring, recordkeeping and reporting requirements for the gas turbines during Natural Gas curtailment periods are also provided under this subdivision.

Within 60 days of becoming a Former RECLAIM Facility, a list of Boilers and Process Heaters shall be submitted identifying which units will meet the Table 4 limits and which will meet Interim NOx emission rate.6

Subdivision (o) – Exemptions

This subdivision includes provisions for specific combustion units which are exempted from compliance with NOx and CO emission limits under low-use, low-emitting, or operating under specific conditions. The following are the Rule 1109.1 exemptions.

Boilers and Process Heaters with rated heat input capacity of 2 MMBtu/hour or less – Paragraph (o)(1)

Small boilers and process heaters (with rated heat input capacity of less than or equal to 2 MMBtu per hour) used for comfort heating that are not used in processing units, are exempt from PR 1109.1. Small natural gas-fired water heaters, boilers, and process heaters (with rated heat input capacity of less than or equal to 2 MMBtu/hr) at PR 1109.1 facilities will be regulated under Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters regulate boilers and heaters.

Low-Use Boilers – Paragraph (o)(2)

Low-use boilers with rated heat input capacity of less than 40 MMBtu/hour that are operated at less than 200 hours per calendar year, are exempt from the emission limits in Table 1 or Table 2. Low-use units have low emissions and high cost-effectiveness to retrofit. Facilities that elect to comply with a B-Plan or B-Cap must have a permit condition limiting operating hours, include the low-use units in the approved B-Plan or B-Cap, conduct source tests pursuant to Rule 1109.1 Table 7 or Table 8, and conduct diagnostic emission checks.

Low-Use Boiler and Process Heaters – Paragraph (o)(3)

Low-use boilers and process heaters with rated heat input capacity of 40 MMBtu/hour or greater that are fired at less than 15 percent of the rated heat capacity per calendar year, are exempt from the emission limits in Table 1, Table 2, or an approved B-Plan. The exemption will be determined based on 15 percent of the fuel use as if the Unit were operated at the Maximum Rated Heat Capacity (e.g., a Unit can only burn up to 15 percent of the maximum fuel the burner could fire if it fired at 100 percent of the Maximum Rated Heat Capacity for 8760 hours per year). Such unit is required to accept a South Coast AQMD permit to operate with a condition that limits the firing rate of the unit to 15 percent of the Rated Heat Input Capacity per year. Low-use units have low emissions and high cost-effectiveness to retrofit. Low-use units will still be subject to all of the other applicable provisions in the rule, must be included in an approved B-Cap (if applicable), and subject to interim emission limits.

FCCU exemption provisions – Paragraphs (o)(4) and (o)(5)

There are several exemption provisions for FCCUs. The first provision is to address boiler inspections required under California Code of Regulations, Title 8, Section 770(b). Some FCCUs with a CO boiler have to by-pass their SCR to safely conduct the inspection and without control an exemption from the emission is needed. For those units, PR 1109.1 provides an exemption from the applicable emission limits.

There is also an exemption for process heaters used to startup the FCCU provided the process heaters is operated for 250 hours or less per calendar year. Facilities that elect to comply with a B-Plan or B-Cap must include such process heater in the approved B-Plan or B-Cap, conduct source tests pursuant to Rule 1109.1 Table 7 or Table 8, and conduct diagnostic emission checks. The unit will have to accept a permit limit with a 250 hour per year or less operating limitation.

Startup and Shutdown Boilers and Process Heaters for Sulfuric Acid Plants– Paragraph (o)(6)

Boilers used for startup and shutdown operations at a sulfuric acid plant are also low-use units that will be exempt from applicable emission limits because to control would not be cost effective. The exemption is based on the current permit limitation which limits the boilers to 90,000 MMBtu of annual heat input per calendar year or less. Startup and Shutdown Boilers that are not included in an approved B-Plan or B-Cap are also exempt from CEMS, source testing, and diagnostic emission checks.

Pilot Exemption for Boilers and Process Heaters – Paragraph (o)(7)

The emission from boilers and process heater operating only the pilot during startup or shutdown are exempt from the applicable emission limits due to low emissions and not cost effective to control.

Flare Exemptions – Paragraph (o)(8)

Non-refinery flares that emit less than or equal to 550 pounds of NOx per calendar year are exempt from the applicable emission limits provided the unit accepts a permit condition with a 550 pound of NOx per year limit. These units are not cost effective to control or replace at this time. Open flares are also exempt from the source test requirement; because there is no stack, these units cannot be source tested.

Vapor Incinerator Exemptions – Paragraph (o)(9)

Vapor incinerators with Rated Heat Input Capacity of 2 MMBtu/hour or less also have a low-emitting exemption if they emit less than 100 pounds of NOx per calendar year. These units are not cost effective to control or replace at this time. Vapor incinerators with Rated Heat Input Capacity of 2 MMBtu/hour or less that emit less than 1000 pounds but more than 100 pounds of NOx per calendar year have a low-emitting exemption until the Unit is replaced or within ten years after date of adoption, whichever happens is sooner. Both classes of vapor incinerators are required to accept a South Coast AQMD permit to operate with a condition that limits the emissions from these units to the applicable level.

PR 1109.1 Attachment A – Supplemental Calculations

This attachment includes calculations for the rolling average calculation for emissions data averaging and the interim NOx emission rate calculation and I-Plan Option 3 emission rate calculation for boilers and heaters greater than or equal to 40 MMBtu/hour or boilers and heaters less than 40 MMBtu/hour that operate with a certified CEMS.

PR 1109.1 Attachment B – Calculation Methodology for the I-Plan, B-Plan, and B-Cap

This attachment includes calculations for the Baseline Emissions; Base Facility BARCT Emission Target; Phase I, Phase II, and Phase III Facility BARCT Emission Target; and Phase I, Phase II, and Phase III BARCT Equivalent Mass Emissions for a B-Plan and B-Cap.

PR 1109.1 Attachment C – Facilities Emissions – Baseline and Targets

Attachment C contains Baseline Facility Emissions as reported by the facilities with six or more units in their 2017 Annual Emissions Reports, or another year, as approved by the Executive Officer. PR 1109.1 Table C-1, presented in the table below, provides the Baseline Facility Emissions for the corresponding facilities subject to PR 1109.1.

Table 2.4-12: PR 1109.1 Table C-1 – Baseline Mass Emissions for Facilities with Six or More Units

Facility	Facility ID	Baseline Facility Emissions (2017 or Representative Year) (tons/year)
AltAir Paramount, LLC	187165	24
Chevron Products Co.	800030	705
Lunday-Thagard Co. DBA World Oil Refining	800080	26
Phillips 66 Company/Los Angeles Refinery	171109	387
Phillips 66 Co/LA Refinery Wilmington PL	171107	456
Tesoro Refining and Marketing Co., LLC – Carson	174655	647
Tesoro Refining and Marketing Co., LLC – Wilmington	800436	597
Tesoro Refining and Marketing Co., LLC – Sulfur Recovery Plant	151798	43
Tesoro Refining and Marketing Co., LLC, Calciner	174591	261
Torrance Refining Company LLC	181667	737
Ultramar Inc.	800026	249
Valero Wilmington Asphalt Plant	800393	4.8

PR 1109.1 Attachment D – Units Qualify for Conditional Limits in B-Plan and B-Cap

Table 2.4-13: PR 1109.1 Table D-1 – Process Heaters and Boilers >40 MMBtu/hr That Qualify for Conditional Limits in B-Plan or B-Cap

Facility ID	Device ID	Size (MMBtu/hr)
171109	D429	352
171109	D78	154
174655	D1465	427
174655	D419	52
174655	D532	255
174655	D63	300
181667	D1236	340
181667	D1239	340
181667	D231	60
181667	D232	60
181667	D234	60
181667	D235	60
181667	D950	64
800026	D1550	245
800026	D6	136
800026	D768	110
800030	D643	220
800030	D82	315
800030	D83	315
800030	D84	219
800030	D466	62
800030	D467	62
800436	D1122	140
800436	D384	48

800436	D385	24
800436	D388	147
800436	D770	63
800436	D777	146

Table 2.4-14: PR 1109.1 Table D-2 – Units That Qualify for Conditional Limits in B-Cap using I-Plan Option 4

Facility ID	Device ID	Size (MMBtu/hr)
171107	D220	350
171107	D686	304
171109	D429	352
171109	D78	154
171109	D79	154
174655	C2979	4
174655	D1465	427
174655	D250	89
174655	D33	100
174655	D419	52
174655	D421	82
174655	D532	255
174655	D539	52
174655	D570	650
174655	D63	360
181667	C686	4
181667	C687	4
181667	D1236	340
181667	D1239	340
181667	D231	60

Facility ID	Device ID	Size (MMBtu/hr)
181667	D232	60
181667	D234	60
181667	D235	60
181667	D920	108
181667	D950	64
800026	D1550	245
800026	D1669	342
800026	D378	128
800026	D429	30
800026	D430	200
800026	D53	68
800026	D6	136
800026	D768	110
800026	D98	57
800030	D453	44
800030	D643	220
800030	D82	315
800030	D83	315
800030	D84	219
800030	D466	62
800030	D467	62
800030	D203	-
800436	D1122	140
800436	D214	56
800436	D215	36
800436	D216	31

Facility ID	Device ID	Size (MMBtu/hr)
800436	D217	31
800436	D33	252
800436	D384	48
800436	D385	24
800436	D386	48
800436	D387	71
800436	D388	147
800436	D770	63
800436	D777	146

Summary of PR 1109.1 (as presented in Draft SEA)

~~**Subdivision (a) – Purpose**~~

~~The purpose of this rule is to reduce emissions of NOx, while not increasing CO emissions, from combustion equipment at petroleum refineries and facilities with related operations to petroleum refineries. PR 1109.1 is needed to transition refineries and facilities with related operations to petroleum refineries from RECLAIM to a command-and-control regulatory structure. PR 1109.1 is a command-and-control rule that is designed to satisfy requirements to establish BARCT under Health and Safety Code Section 40920.6 which implements AB 617.~~

~~**Subdivision (b) – Applicability**~~

~~PR 1109.1 applies to combustion equipment at petroleum refineries and facilities with related operations to petroleum refineries, including asphalt plants, biofuel plants, hydrogen production plants, petroleum refineries, facilities that operate petroleum coke calciners, sulfuric acid plants, and sulfur recovery plants. The provisions of PR 1109.1 apply to petroleum refineries and facilities with related operations to petroleum refineries while in RECLAIM and after they transition out of RECLAIM. Combustion equipment which are subject to this rule are categorized as boilers, flares, fluid catalytic cracking units, gas turbines, petroleum coke calciners, process heaters, steam methane reformer heaters, sulfuric acid furnaces, SRU/TG incinerators, and vapor incinerators.~~

~~**Subdivision (c) – Definitions**~~

~~Definitions in PR 1109.1 are incorporated to define equipment, fuels, and other rule terms. Below are some key definitions that are used in PR 1109.1, refer to PR 1109.1 for a complete list of definitions.~~

~~PR 1109.1 defines "facilities with the same ownership" because the alternative compliance plans and interim emission limits allow all units at facilities with the same ownership to be considered in one compliance plan and in the interim emission limits for boilers and process heaters 40 MMBtu/hour or greater.~~

- ~~FACILITIES WITH SAME OWNERSHIP means facilities and their subsidiaries, or facilities that share the same Board of Directors or share the same parent corporation.~~

~~At time of this SEA, the following are the PR 1109.1 facilities with the same ownership:~~

~~Table 2.4-1: Facilities with Same Ownership~~

~~Owner~~	~~Facility~~	~~Facility ID~~
~~Marathon Petroleum Company/Tesoro Refining and Marketing, LLC (Marathon)~~	~~Tesoro – Carson~~	~~174655~~
	~~Tesoro – Wilmington~~	~~800436~~
	~~Tesoro – Sulfur Recovery Plant~~	~~151798~~
	~~Tesoro – Petroleum Coke Calciner~~	~~174591~~
~~Phillips 66~~	~~Phillips 66 – Carson~~	~~171109~~
	~~Phillips 66 – Wilmington~~	~~171107~~
~~Valero~~	~~Ultramar/Valero Wilmington~~	~~800026~~
	~~Valero Asphalt Plant~~	~~800393~~

~~The definition of "unit" was included to streamline the rule language.~~

- ~~UNIT means, for the purpose of this rule, boilers, flares, FCCUs, gas turbines, petroleum coke calciners, process heaters, SMR heaters, sulfuric acid furnaces, SRU/TG incinerators, or vapor incinerators requiring a South Coast AQMD permit and not required to comply with another NOx emission limit in a South Coast AQMD Regulation XI rule.~~

~~Many units at PR 1109.1 are combined through common ducting to allow a single air pollution control device to control the emissions of several units. PR 1109.1 includes a definition for "units with combined stacks" to clarify how the provisions apply to those units.~~

- ~~UNITS WITH COMBINED STACKS means two or more units where the flue gas from these units are combined in one or more common stack(s).~~

~~Subdivision (d) – Emissions Limits~~

~~This subdivision establishes the proposed BARCT and conditional NOx and CO emission limits for combustion equipment at petroleum refineries and facilities with operations related to petroleum refineries. PR 1109.1 Table 1 lists the NOx and CO emissions limits for different classes and categories of equipment subject to this rule and identifies the corresponding rolling averaging times and percent of oxygen as the basis for emissions measurement or calculation. PR 1109.1 Table 1, Table 2, and Table 3 establish averaging times over which the NOx concentration limits must be met. Averaging times must be calculated as established in Attachment A of PR 1109.1 for any unit that operates with CEMS. All averaging times based on CEMS are rolling averages and are established for different types of equipment in Table 1, Table 2, and Table 3 of PR 1109.1. Averaging times for units that must demonstrate compliance with a source test are required to demonstrate compliance based on the time specified in the approved source test protocol as discussed in subdivision (k).~~

~~Table 2.4-2: PR 1109.1 Table 1 – NOx and CO Emission Limits~~

~~Unit~~	~~NOx (ppmv)~~	~~CO (ppmv)~~	~~O_2 Correction (%)~~	~~Rolling Averaging Time[1]~~
~~Boilers <40 MMBtu/hour~~	~~Pursuant to paragraph (d)(3)~~	~~400~~	~~3~~	~~24-hour~~
~~Boilers ≥40 MMBtu/hour~~	~~5~~	~~400~~	~~3~~	~~24-hour~~
~~FCCU~~	~~2~~	~~500~~	~~3~~	~~365-day~~
	~~5~~			~~7-day~~
~~Flares~~	~~20~~	~~400~~	~~3~~	~~2-hour~~
~~Gas Turbines fueled with Natural Gas~~	~~2~~	~~130~~	~~15~~	~~24-hour~~
~~Gas Turbines fueled with Gaseous Fuel other than Natural Gas~~	~~3~~	~~130~~	~~15~~	~~24-hour~~
~~Petroleum Coke Calciner~~	~~5~~	~~2,000~~	~~3~~	~~365-day~~
	~~10~~			~~7-day~~
~~Process Heaters <40 MMBtu/hour~~	~~Pursuant to paragraph (d)(4)~~	~~400~~	~~3~~	~~24-hour~~
~~Process Heaters ≥40 MMBtu/hour~~	~~5~~	~~400~~	~~3~~	~~24-hour~~
~~SMR Heaters~~	~~5~~	~~400~~	~~3~~	~~24-hour~~
~~SMR Heaters with Gas Turbine~~	~~5~~	~~130~~	~~15~~	~~24-hour~~
~~SRU/TG Incinerators~~	~~30~~	~~400~~	~~3~~	~~24-hour~~
~~Sulfuric Acid Furnaces~~	~~30~~	~~400~~	~~3~~	~~365-day~~
~~Vapor Incinerators~~	~~30~~	~~400~~	~~3~~	~~24-hour~~

~~1 Averaging times apply to units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for units without CEMS are specified in subdivision (k).~~

~~Conditional NOx and CO Limits – Paragraph (d)(2)~~

~~PR 1109.1 provides alternative BARCT NOx limits for units which are currently operating at or below NOx concentration limits in Table 2 of PR 1109.1. This provision is designed to recognize~~

~~that some units have existing pollution controls that are currently operating near the NOx limits in PR 1109.1 Table 1 and it is not cost-effective to require replacement or installation of additional pollution controls. PR 1109.1 includes several conditions that an owner or operator must meet if an operator elects to meet the NOx and CO limits in Table 2, in lieu of the NOx and CO limits in Table 1.~~

~~PR 1109.1 has two pathways for operators to use PR 1109.1 Table 2 conditional limits. The first pathway is through meeting all of the conditions specified under subparagraph (d)(2)(A) and (d)(2)(B). Under this first pathway, the operator must meet all of the conditions specified under subparagraph (d)(2)(A) and submit a permit application by July 1, 2022. Additional details regarding the conditions are discussed below. The second pathway is for units that are identified in Attachment D of PR 1109.1. Attachment D includes Table D-1 which applies to facilities with a B-Plan or a B-Cap and includes those units that were identified in the cost-effectiveness as part of establishing the conditional limits. Table D-2 applies to facilities with a B-Cap that have selected I-Plan Option 4 and includes those units that meet all of the conditions in subparagraph (d)(2)(A) and that have a representative NOx concentration at or below 25 ppmv. Units listed under Table D-2 were added since an operator that is implementing I-Plan Option 4 will achieve 50 to 60 percent of their targeted emission reductions by January 1, 2024. Both pathways are designed to achieve earlier NOx reductions to be consistent with the intent of AB 617.~~

~~Under subparagraph (d)(2)(A), the first condition for a unit to be allowed a Table 2 conditional limit is that the Executive Officer has not issued a Permit to Construct on or after December 4, 2015 for the installation of a pollution control device. This condition is to prevent units with recently installed pollution control devices, such as SCR, which can achieve the Table 1 emission limits from electing to comply with Table 2 conditional limits. December 4, 2015 was selected as this is the date when Regulation XX – RECLAIM was amended to reduce or shave allocations. The analysis was based on a technical analysis that large boilers and heaters could achieve a NOx concentration of 2 ppmv. Staff believes that units modified after this date should have been designed to achieve the proposed Table 1 NOx limit of 5 ppmv for large boilers and heaters. This condition will also ensure units that can achieve significant NOx reductions in a cost-effective manner, are required to meet the NOx and CO emission limits under Table 1 of PR 1109.1.~~

~~The next two conditions are that emission reduction projects for process heaters between 40 – 110 MMBtu/hour could not have an emission reduction potential of reducing 10 tons per year or more and emission reduction projects for boilers or process heaters >110 could not have an emission reduction potential of reducing 20 tons per year or more. The potential emission reductions are based on the difference of the baseline emissions and the Table 1 concentration, scaled to the baseline emissions.~~

> ~~FACILITY BARCT EMISSION TARGET means the total mass emissions per facility calculated based on the applicable Table 1 NOx emission limits or Table 2 conditional NOx limits and the 2017 annual NOx emissions, or another representative year as approved by the Executive Officer.~~

~~The last two conditions are that the unit must not have an existing permit limit at or below the Table 1 NOx~~

~~limits, or have a Representative NOx concentration that is at or below the Table 1 NOx limits. These conditions will prevent units that are achieving NOx emissions that meet the Table 1 NOx limits from electing to comply with the conditional limits. Units that meet the conditions for the Table 2 emission limits must submit a permit application by July 1, 2022 and meet the permit limits no later than 18 months from the issuance of the Permit to Construct.~~

~~Secondly, for a B-Plan, an operator electing to meet the conditional NOx limit must submit a permit application by July 1, 2022, unless the unit is identified in Table D-1 of PR 1109.1. Staff is proposing July 1, 2022 to coincide with the submittal of an I-Plan and B-Plan. A commitment that an operator will be meeting the conditional NOx limit is needed to allow an operator to account for a unit that is seeking compliance with Table 2 in lieu of Table 1 NOx limits when calculating the Facility BARCT Emission Target. Implementation of the conditional limits by requiring a permit application by July 1, 2022 will help to expedite BARCT consistent with AB 617.~~

~~The proposed NOx and CO conditional limits are listed in the table below.~~

~~Table 2.4-3: PR 1109.1 Table 2 – Conditional NOx and CO Emission Limits~~

~~Unit~~	~~NOx (ppmv)~~	~~CO (ppmv)~~	~~O_2 Correction (%)~~	~~Rolling Averaging Time~~[1]
~~Boilers >110 MMBtu/hour~~	~~7.5~~	~~400~~	~~3~~	~~24-hour~~
~~FCCU~~	~~8~~	~~500~~	~~3~~	~~365-day~~
	~~16~~			~~7-day~~
~~Gas Turbines fueled with Natural Gas~~	~~2.5~~	~~130~~	~~15~~	~~24-hour~~
~~Process Heaters 40 – 110 MMBtu/hour~~	~~18~~	~~400~~	~~3~~	~~24-hour~~
~~Process Heaters >110 MMBtu/hour~~	~~22~~	~~400~~	~~3~~	~~24-hour~~
~~SMR Heaters~~	~~7.5~~	~~400~~	~~3~~	~~24-hour~~
~~Vapor Incinerators~~	~~40~~	~~400~~	~~3~~	~~2-hour~~

~~[1] Averaging times apply to units operating a certified CEMS and shall be calculated pursuant to Attachment A of this rule. Requirements, including averaging times, for units without CEMS are specified in subdivision (k).~~

~~Proposed NOx Limits for Boilers and Process Heaters with a Rated Heat Input Capacity Less than 40 MMBtu/hr – Paragraphs (d)(3) and (d)(4)~~

~~PR 1109.1 establishes an initial NOx limit of 40 ppmv for boilers and process heaters smaller than 40 MMBtu/hr with consideration for lower NOx limits when burners are replaced. On or before January 1, 2023, operators must modify existing permits for these boilers and process heaters to limit NOx to 40 ppmv and CO to 400 ppmv at three percent O_2. CO limit, percent of O_2, and if applicable, meet the averaging time in PR 1109.1 Table 1.~~

~~The NOx limit of 40 ppmv is lowered to 5 ppmv for boilers and 9 ppmv for process heaters when either the operator cumulatively replaces 50 percent or more of the burners or the burners replaced cumulatively represent 50 percent or more of the heat input. The cumulative replacement of burners begins to be effective from July 1, 2022. Since the emission reduction technologies for process heaters are based on emerging technologies, the NOx limit of 9 ppmv is applicable ten years after rule adoption to provide time for specific emerging technologies. The cumulative burner replacement provision applies from date of rule adoption to prevent a facility from replacing burners incrementally over time in order not to trigger a retrofit. Operators are required to maintain records for burner replacement for these boilers and process heaters to track burner replacement. Staff believes that implementation of the B-Plan and B-Cap will help incentivize operators to accelerate introduction and commercialization of emerging technologies. Staff will monitor the development of the emerging technologies and will include in the Resolution a commitment to report on the status of the emerging technologies in 2029 and conduct a technology assessment if these technologies are not being commercialized.~~

~~*Gas Turbines Operating on Natural Gas – Paragraph (d)(5)*~~
~~PR 1109.1 provides an alternative NOx emission limit of 5 ppmv (corrected to 15 percent oxygen on dry basis) based on a 24-hour rolling average, instead of the 2-ppmv and 5-ppmv NOx limits for gas turbines operating on natural gas and refinery gas, respectively, during natural gas curtailment periods. Natural gas curtailment occurs when there is a shortage in the supply of pipeline natural gas due to limitations in the supply or restrictions in the distribution pipelines by the utility that supplies natural gas. A shortage in natural gas supply that is due to changes in the price of natural gas does not qualify as a natural gas curtailment. CO Emission Limits in Table 1 and Table 2 of PR 1109.1.~~

~~*Units with Combined Stacks – Paragraph (d)(6)*~~
~~Paragraph (d)(6) requires units with combined stacks to meet the most stringent applicable Table 1 or Table 2 NOx limits. This provision addresses which requirements apply to combined units if one or more of the units fall in a different size category as follows:~~

- ~~If multiple units are combined:~~
  - ~~One unit is >110 MMBtu/hr and the other are less~~ → ~~>110 MMBtu/hr~~
  - ~~All units are between 40 – 110 MMBtu/hr~~ → ~~40 – 110 MMBtu/hr~~
  - ~~One is >40 MMBtu/hr and the other units are less~~ → ~~40 – 110 MMBtu/hr~~

~~*CO Limits – Paragraph (d)(7)*~~
~~PR 1109.1 Table 1 and Table 2 establish CO limits for each class and category of equipment. As discussed, the purpose of this rule is to reduce emissions of NOx from combustion equipment at petroleum refineries and facilities with related operations to petroleum refineries, with no increase in the associated CO emissions. The CO emissions for the classes and categories of equipment listed in PR 1109.1 Table 1 and Table 2 are generally representative of CO limits in permits and consistent with other rules regulating similar combustion equipment. If a unit has a CO emission limit established in a Permit to Operate before the date of rule adoption, the owner or operator must meet the CO emission limit in the Permit to Operate in lieu of the CO emission limit specified in Table 1 or Table 2 of PR1109.1. The CO permit limit can include an actual permit limit or a reference to South Coast AQMD Rule 407 – Liquid and Gaseous Air Contaminants.~~

~~Owner or operators with six or more units, have the option to use a B-Plan or B-Cap that will allow the selection of a NOx limit that may be higher than the NOx limits established in PR 1109.1~~

~~However, regardless of the NOx limit selected in a B-Plan or B-Cap, the operator is required to meet the applicable CO emission limit in Table 1 or Table 2.~~

~~*Provisional Averaging Time - Paragraph (d)(8)*~~

~~During the rulemaking process some operators commented that achieving the shorter averaging times and lower NOx levels in PR 1109.1 will be challenging as operators are currently held to an annual compliance cycle under the RECLAIM program. Achieving the proposed NOx limits in Table 1 and 2 under PR 1109.1 will require a shorter compliance periods for all units other than the FCCUs, Petroleum Coke Calciner, and Sulfuric Acid Plants, which will be subject to 365-day rolling averages. To address this additional challenge, for units subject to a rolling average less than a 365-days, compliance with the applicable limits needs to be demonstrated six months after either the issuance of the Permit to Operate, or 36 months after the Permit to Construct is issued, or completion of a compliance demonstration source test, whichever is sooner. This consideration allows for applying any necessary adjustments to ensure NOx emission levels can be met within the required averaging times.~~

~~*Initial Averaging Time for Units with a 365-Day Averaging Time Period – Paragraph (d)(9)*~~

~~An owner or operator of a unit subject to a 365-day rolling average shall demonstrate compliance with the Rule 1109.1 Emission Limits beginning 14 months after either the South Coast AQMD Permit to Operate is issued, 36 months after the Permit to Construct is issued, or completion of a compliance demonstration source test, whichever is sooner. This consideration allows for applying any necessary adjustments to ensure NOx emission levels can be met within the required averaging times.~~

~~**Subdivision (e) – B-Plan and B-Cap requirements**~~

~~PR 1109.1 includes two alternative compliance options to directly meeting the NOx limits in Table 1 or Table 2 for operators with six or more units. Total mass emissions are calculated from all units complying with applicable Table 1 or Table 2 NOx limits with the exception of any boiler or process heater less than 40 MMBtu/hour that will meet the 5 ppmv or 9 ppmv NOx emission limit upon burner replacement after the final compliance date in the selected I-Plan option. Then, the alternative concentration limits for each unit in the B-Plan are identified and calculated to ensure that the units at those alternative concentration levels will enable the facility to achieve no greater emissions calculated with Table 1 or 2 assuming operations at 2017 levels. Those concentration limits are then set as permit requirements, allowing facilities to operate at whatever levels their permits otherwise allow.~~

~~Operators can submit a B-Plan which will achieve the Table 1 or Table 2 limits, provided conditions are met, in aggregate based on 2017 emissions. Under the B-Plan, operators would meet Alternative BARCT NOx Limits, with no mass emission cap, similar to a traditional command-and-control regulatory rule. Alternative BARCT NOx limits shall not exceed the Conditional NOx and CO limit in Table 2, if applicable. If the operator has units that are identified in Attachment D of PR 1109.1, an application is not required by July 1, 2022 as provided under subparagraph (d)(2)(C). Alternatively, operators can submit a B-Cap where operators would meet Alternative BARCT NOx limits as well as maintaining NOx emissions below an emission cap. Emission reductions from decommissioning units and units with reduced throughputs or other emission reduction strategies would allow higher Alternative BARCT NOx Limits for other units in the B-Cap, provided the overall mass emissions are below the emissions cap and the Alternative BARCT NOx limits do not exceed the Maximum Alternative NOx concentration limits in Table 3 in PR 1109.1.~~

- ~~I-PLAN means an implementation plan for facilities with six or more units that includes an alternative implementation schedule to paragraph (g)(1) and emission reduction targets.~~
- ~~B-CAP means a compliance plan that establishes a mass emission cap for all units subject to this rule that are equivalent, in aggregate, to the Facility BARCT Emission Target.~~
- ~~B-PLAN is a compliance plan that allows an owner or operator to select NOx concentration limits achieve NOx reductions that that are equivalent, in aggregate, to the NOx concentration limits specified in Table 1 and Table 2 of this rule for units to be included in the B-Plan.~~

~~Regardless if the operator is complying with PR 1109.1 through a B-Plan or B-Cap, each and every unit must have an enforceable permit at the time of full compliance with the requirements of PR 1109.1.~~

~~Table 2.4-4: PR 1109.1 Table 3 – Maximum Alternative BARCT NOx Limits for a B-Cap~~

~~Unit~~	~~Alternative NOx Limit (ppmv)~~	~~O_2 Correction (%)~~
~~Boilers and Process Heaters <40 MMBtu/hour~~	~~40 ppmv~~	~~3~~
~~Boilers and Process Heaters ≥40 MMBtu/hour~~	~~50 ppmv~~	~~3~~
~~FCCU~~	~~8 ppmv~~	~~3~~
~~Gas Turbines~~	~~5 ppmv~~	~~15~~
~~Petroleum Coke Calciner~~	~~100 tons/year~~	~~N/A~~
~~SRU/TG Incinerator~~	~~50 ppmv~~	~~3~~
~~Vapor Incinerator~~	~~40 ppmv~~	~~3~~

~~Requirements for the B-Plan and B-Cap - Paragraph (e)(1) and (e)(2)~~

~~Paragraphs (e)(1) and (e)(2) establish the requirements for the B-Plan and B-Cap, respectively. Operators must submit the B-Plan or B-Cap by July 1, 2022. Both the B-Plan and B-Cap require operators to accept permit limits that reflect the Alternative BARCT Limits in the B-Plan and B-Cap and to meet those concentration limits based on the schedule in the approved I-Plan. In the B-Cap the Alternative BARCT NOx limit cannot exceed Table 3 of PR1109.1 as shown in the table above.~~

~~Under the B-Cap, a facility can permanently decommission a unit to meet the Facility BARCT Target since emissions from all units are "capped" and the facility is meeting BARCT based on mass emissions. The owner of a unit that is selected to be decommissioned under a B-Cap is required to reflect the emissions from the decommissioned unit as Table 1 emissions in the Phase I, Phase II, and if applicable Phase III Facility BARCT Emission Target in an approved B-Cap.~~

~~For any unit that is decommissioned, the South Coast AQMD Permit to Operate must be surrendered, and the owner shall disconnect and blind the fuel line(s) to the unit and not sell the unit for operation to another entity within the South Coast Air Basin.~~

~~PR 1109.1 includes additional requirements for the B-Cap, which include limiting the cumulative NOx emissions for all units in the B-Cap to at or below the Facility BARCT Emission Targets based on a 365-day rolling daily demonstration. The operator cannot add a new unit to the facility without the emissions from that unit being included in the B-Cap mass emissions calculation that is applicable to PR 1109.1, unless:~~

- ~~All units in the approved B-Cap meet Table 1 NOx limits and applicable Table 2 NOx limits in aggregate;~~
- ~~The new unit is not functionally similar to any unit that was decommissioned in the approved B-Cap;~~
- ~~The new unit will not increase overall throughput of the facility; or~~
- ~~The total amount of NOx emission reductions from units that were decommissioned, represents 15 percent or less of final phase of the Facility BARCT Emission Target in an approved B-Cap.~~

~~The provisions for new units and unit decommissioning are to prevent a facility from shutting down units instead of installing controls on units. While shutting down a unit will result in emission reductions, the intent of PR 1109.1 is to require facilities to have BARCT levels of control on all units, or BARCT equivalent emissions in the aggregate. If a facility were to decommission a unit, take credit for the emission reductions in the B-CAP, and later install a functionally similar unit outside the B-Cap, the B-Cap would no longer be BARCT equivalent. It would not be equitable that the emissions budget from decommissioning a unit was used to allow another unit to not install pollution controls, and later install a unit that is functionally similar to the unit that was decommissioned. The provision to limit the NOx reductions in a B-CAP is to prevent a facility from shutting down some large emitting units in lieu of retrofitting a significant number of units at the facility.~~

~~Subdivision (f) – Interim Limits~~

~~Interim NOx limits are needed after facilities transition out of RECLAIM and before the unit meets the NOx limits in PR 1109.1 to ensure there is no backsliding and interference with attainment. PR 1109.1 includes interim limits that are based on permit limits and actual emissions data. Except for interim limits for boilers and process heaters 40 MMBtu/hour and greater, all interim limits are a specific NOx concentration limit and provide a 365-day averaging period. PR 1109.1 is proposing a 365-day averaging period to minimize disruptions as facilities transition out of RECLAIM. Interim limits for all units except boilers and process heaters 40 MMBtu/hour and greater are provided in Table 4 of PR 1109.1 and are presented below.~~

~~Table 2.4-5: PR 1109.1 Table 4 – Interim NOx and CO Emission Limits~~

~~Unit~~	~~NOx (ppmv)~~	~~CO (ppmv)~~	~~O_2 Correction (%)~~	~~Rolling Averaging Time[1]~~
~~Boilers and Process Heaters <40 MMBtu/hour~~	~~40~~	~~400~~	~~3~~	~~365-day~~
~~Boilers and Process Heaters ≥40 MMBtu/hour~~	~~Pursuant to paragraph (f)(2)~~	~~400~~	~~3~~	~~365-day~~
~~Flares~~	~~105~~	~~400~~	~~3~~	~~365-day~~
~~FCCU~~	~~40~~	~~500~~	~~3~~	~~365-day~~
~~Gas Turbines fueled with Natural Gas or Other Gaseous Fuel~~	~~20~~	~~130~~	~~15~~	~~365-day~~
~~Petroleum Coke Calciner~~	~~85~~	~~2,000~~	~~3~~	~~365-day~~
~~SRU/TG Incinerators~~	~~100~~	~~400~~	~~3~~	~~365-day~~
~~SMR Heaters~~	~~20[2]~~	~~400~~	~~3~~	~~365-day~~
	~~60[3]~~			~~365-day~~
~~SMR Heaters with Gas Turbine~~	~~5~~	~~130~~	~~15~~	~~365-day~~
~~Sulfuric Acid Furnaces~~	~~30~~	~~400~~	~~3~~	~~365-day~~
~~Vapor Incinerators~~	~~105~~	~~400~~	~~3~~	~~365-day~~

~~[5] Averaging times are applicable to units with a CEMS and shall be calculated pursuant to Attachment A of this rule. Averaging times for units without CEMS are specified in subdivision (k).~~

~~[6] SMR Heaters with post-combustion air pollution control equipment installed before [*DATE OF ADOPTION*].~~

~~[7] SMR Heaters without post-combustion air pollution control equipment installed before [*DATE OF ADOPTION*].~~

~~*Interim Limits for Boilers and Process Heaters with CEMS – Paragraph (f)(2)*~~

~~For boilers and process heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour, staff found substantial variation in the NOx concentration levels with no definitive groupings of units to establish a specific NOx concentration limit for these units. PR 1109.1 establishes different NOx limits for all boilers and process heaters with a rated heat input capacity at or greater than 40 MMBtu/hour and the ones with a rated heat input capacity less than 40 MMBtu/hour that operate a certified CEMS (based on the maximum rated capacity) based on the operator choice of B-Plan or B-Cap (PR 1109.1 Table 5). This provision will be implemented until the last unit in this class meets the final NOx concentration limit to ensure that as units comply with the NOx concentration limit, the remaining units do not exceed the applicable threshold established in PR 1109.1 Table 5.~~

~~Table 2.4-6: PR 1109.1 Table 5 – Interim NOx Emission Rates for Boilers and Process Heaters~~

~~Units~~	~~An Owner or Operator that Elects to Comply with an Approved:~~	~~Facility NOx Emission Rate (pounds/million Btu)~~	~~Rolling Averaging Time~~
~~Boilers and Process Heaters: ≥40 MMBtu/Hour and <40 MMBtu/hour Operating a Certified CEMS~~	~~B-Plan using I-Plan Option 3~~	~~0.02~~	~~365-day~~
	~~B-Plan~~	~~0.03~~	~~365-day~~

~~The calculation to determine a facility's NOx levels is included in Attachment E of the rule and as follows:~~

- ~~Annual Mass Emissions (lbs/hour)~~
  ~~Sum the actual annual mass emissions of all boilers and process heaters with a rated heat input capacity at or greater than 40 MMBtu/hour and any boilers and process heaters with a rated heat input capacity less than 40 MMBtu/hour that operate a certified CEMS, and divide by 8760 hours for lbs per hour.~~

- ~~Combined Maximum Heat Input (MMBtu/hour)~~
  ~~Sum the combined maximum rated heat input for all boilers and process heaters with a rated heat input capacity at or greater than 40 MMBtu/hour and any boilers and process heaters with a rated heat input capacity less than 40 MMBtu/hour that operate a certified CEMS.~~

- ~~Interim Facility Wide NOx Emission Rate (lbs/MMBtu)~~
  ~~Divide the Hourly Mass Emissions in Section (E-1.1) by the combined Maximum Heat Input in Section (E-1.2) to determine the interim facility-wide NOx emission rate.~~

~~*Interim Limits for a facility that elects to comply with a B-Cap – Paragraph (f)(3)*~~

~~Facilities that elect to comply with a B-Cap will not be held to the NOx concentrations limits in Table 4 or Table 5 of PR 1109.1. The interim limits are intended to prevent emission increases once a facility exists RECLAIM and before all the PR 1109.1 emission limit apply. To achieve this for the facilities complying with an approved B-Cap, facilities will be held to their Baseline Facility Emissions which is based on the 2017 annual emissions, or a lower limit based on the percent reduction in the approved I-Plan and when the facility exits RECLAIM.~~

~~**Subdivision (g) – Compliance Schedule**~~

~~This subdivision establishes the implementation schedules for combustion equipment at petroleum refineries and facilities with operations related to petroleum refineries to comply with PR 1109.1 requirements. There are two main implementation pathways. The first pathway would require the operator to submit permit applications by July 1, 2023 and the second alternative pathway, which is available to facilities with six or more units, is to submit an I-Plan which is an implementation plan that includes an alternative implementation schedule with emission reduction targets.~~

~~*Compliance with Table 1 – Paragraph (g)(1)*~~

~~This paragraph requires an owner or operator to submit a permit application to establish a NOx limit in a permit on or before July 1, 2023. Operators must meet the NOx and CO concentration limits in PR 1109.1 Table 1 no later than 36 months after a Permit to Construct is issued. Operators with a Permit to Construct or a Permit to Operate that already limits the NOx concentration consistent with Table 1 are not required to submit a permit application. This is the only compliance pathway for facilities with less than six units. For facilities with six or more units, PR 1109.1 provides this compliance pathway as well as an alternative implementation schedule under the I-Plan.~~

~~*I-Plan Requirements – Paragraph (g)(2)*~~

~~An I-Plan is an implementation plan that includes an alternative implementation schedule to paragraph (g)(1). An I-Plan is required for facilities that elect to comply with either a B-Plan or a B-Cap or a facility that elects to have an alternative compliance schedule for meeting Table 1 or Table 2 emission limits. An owner or operator with six or more units has the option to submit an I-Plan to meet the NOx and CO emission limits specified in PR 1109.1 Table 1 or Table 2 . The purpose of the I-Plan is to allow facilities the flexibility to select the group of units that will implement emission reduction projects for each phase, provided the group of units and their associated emission reductions meet the emission reduction targets established under the I-Plan which are specified in Table 6 of PR 1109.1. The I-Plan allows refineries to implement projects within their turnaround schedules to minimize operational disruptions. Staff consulted with refineries to develop the proposed I-Plan timeframes and percent reductions. The I-Plan is designed to implement the Table 1, and if eligible Table 2, the B-Plan, or the B-Cap. The I-Plan can include all the units under one facility or all the units under a facility with same ownership with the exception of any boiler or process heater less than 40 MMBtu/hour that will meet the NOx limit specified in subparagraph (d)(3)(C) or (d)(4)(C) after the last Compliance Date in PR 1109.1 Table 6 for the selected I-Plan option.~~

~~Table 2.4-7: PR 1109.1 Table 6 – I-Plan Targets and Schedule~~[~~(1)~~]

		~~Phase I~~	~~Phase II~~	~~Phase III~~
~~I-Plan Option 1 B-Plan Only~~	**~~Percent Reduction Targets~~**	**~~70~~**	**~~100~~**	**~~N/A~~**
	~~Permit Application Submittal Date~~	~~July 1, 2023~~	~~January 1, 2027~~	~~N/A~~
	~~Compliance Date~~	~~No later than 36 months after a Permit to Construct is issued~~		~~NA~~
~~I-Plan Option 2 B-Plan Only~~	**~~Percent Reduction Targets~~**	**~~60~~**	**~~80~~**	**~~100~~**
	~~Permit Application Submittal Date~~	~~July 1, 2023~~	~~January 1, 2025~~	~~January 1, 2028~~
	~~Compliance Date~~	~~later than 36 months after a Permit to Construct is issued~~		
~~I-Plan Option 3 for B-Plan or B-Cap and as allowed pursuant to paragraph (g)(3)~~	**~~Percent Reduction Targets~~**	**~~50~~**	**~~100~~**	**~~N/A~~**
	~~Permit Application Submittal Date~~	~~January 1, 2025~~	~~January 1, 2029~~	~~N/A~~
	~~Compliance Date~~	~~No later than 36 months after a Permit to Construct is issued~~		~~N/A~~
~~I-Plan Option 4 for B-Cap Only~~	**~~Percent Reduction Targets~~**	**~~50 to 60 (Still in development)~~**	**~~80~~**	**~~100~~**
	~~Permit Application Submittal Date~~	~~N/A~~	~~January 1, 2025~~	~~January 1, 2028~~
	~~Compliance Date~~	~~January 1, 2024~~	~~No later than 36 months after a South Coast AQMD Permit to Construct is issued~~	
~~I-Plan Option 5 for B-Plan Only~~	**~~Percent Reduction Targets~~**	**~~50~~**	**~~70~~**	**~~100~~**
	~~Permit Application Submittal Date~~	~~July 1, 2022~~	~~July 1, 2024~~	~~January 1, 2028~~
	~~Compliance Date~~	~~No later than 36 months after a South Coast AQMD Permit to Construct is issued~~		

~~[1] Percent Reduction Targets represent refinery-wide emission reductions including Facilities with Same Ownership.~~

~~Any operator that submits either a B-Plan or a B-Cap is required to submit an I-Plan. The I-Plan requirements are different for the B-Plan and B-Cap. For operators using a B-Plan, key requirements are to submit an I-Plan for review and approval by July 1, 2022, calculate the Facility BARCT Emission Target for each phase of the I-Plan, and to implement the approved B-Plan based on the schedule in the approved I-Plan that meets one of the I-Plan options in PR 1109.1 Table 6. For facilities using a B-Cap, the key requirements for the I-Plan are similar with the additional provisions for a 10 percent reduction to the Facility BARCT Emission Targets and specificity regarding when the reduction in the mass cap will occur relative to the schedule in Table 6 of PR 1109.1.~~

~~Since the B-Cap establishes a mass emissions cap compliance option, the Facility BARCT Emission Target is proposed to be reduced by 10 percent. U.S. EPA has initially commented that pursuant to U.S. EPA's January 2001 Improving Air Quality with Economic Incentive Programs, a 10 percent environment benefit will likely be required. Staff is continuing to discuss the elements of the B-Cap with U.S. EPA. PR 1109.1 requires that the reduction in the Facility BARCT Emission Target reflecting the Percent Reduction Targets in PR 1109.1 Table 6, be applied 54 months after the permit application is required for each phase of the selected I-Plan option in PR 1109.1 Table 6. The 54-month requirement is based on 18 months between submittal of a permit application and issuance of a Permit to Construct plus 36 months to meet the Alternative BARCT NOx Limit in the approved B-Cap. For facilities with a B-Cap meeting I-Plan Option 4, the Phase I BARCT Emission Target shall be met on or before January 1, 2024.~~

~~Staff does not view the implementation period provided in Rule 1109.1 to be in conflict with Rule 205 that states "A permit to construct shall expire one year from the date of issuance unless an extension of time has been approved in writing by the Executive Officer." This rule and its general provisions will have the approval of the Executive Officer unless the rule requires an additional Executive Officer approval (e.g., an I-Plan, B-Plan, B-Cap, etc.).~~

~~*Applicability of I-Plan Option 3 – Paragraph (g)(3)*~~

~~I-Plan Option 3 is only available to the owner or operator of a facility that is achieving a NOx emission rate of less than 0.02 pound per million BTU of heat input for all the boilers and process heaters with a rated heat input capacity greater than or equal to 40 MMBtu/hour or any boiler or process heater less than 40 MMBtu/hours operates with a certified CEMS, based on the maximum rated capacity. The facility would be required to perform a one-time demonstration that their applicable boilers and heaters meet the 0.02 pound per million BTU emission rate based on the 2021 annual emissions for those units as reported in the 2021 Annual Emissions Report.~~

~~*Modifications to Existing Units that are Meeting Table 2 Conditional NOx Limits – Paragraph (g)(4)*~~

~~A unit complying with a Table 2 conditional limit under subparagraphs (d)(2)(A) and (d)(2)(B) will be required to submit a permit application, accept the NOx concentration limit in Table 1 and meet the NOx and CO concentration limits at the percent oxygen and averaging times in Table 1 if the NOx post-combustion air pollution control equipment is replaced for an FCCU, gas turbine fueled with natural gas, process heater with a heat input capacity at or greater than 40 MMBtu/hour, or SMR heater. A vapor incinerator complying with a Table 2 conditional limit will be required to submit a permit application, accept the NOx concentration limit in Table 1 and meet the NOx and CO concentration limits at the percent oxygen and averaging times in Table 1 if more than 50 percent of the burners are cumulatively replaced. The provision for replacing NOx post-~~

~~combustion controls applies only if the post-combustion controls is greater than 50 percent of the fixed capital cost that would be required to construct a similar new unit. This provision is to ensure that if an operator is making a significant modification to the listed equipment, then the operator will be required to meet the Table 1 NOx and CO emission limits. A unit complying with Table 2 conditional limits under subparagraph (d)(2)(C) is required to submit the permit application based on their approved B-Plan or approved B-Cap. These units may select Alternative BARCT Emission Limits that are different than Table 2, but the selected Alternative BARCT Emission Limit must be incorporated into the operator's permit to operation.~~

~~*Paragraph (g)(5)*~~

~~If an owner or operator fails to submit a permit application when required to, the unit shall meet the applicable rule limit no more than 36 months after the application was due. This will prevent undue delays of air pollution control equipment installation because permit applications were not submitted in a timely manner.~~

~~*Exempted Units - Paragraph (g)(6)*~~

~~This paragraph requires units that are exempt from PR 1109.1 Table 1 NOx and CO limits under specific provisions in subdivision (n) to submit a permit application within six months from the time they exceed the applicable exemption thresholds and to meet the NOx and CO emission limit in PR 1109.1 Table 1 within 36 months after the Permit to Construct is issued.~~

~~**Subdivision (h) – Time Extension**~~

~~PR 1109.1 allows two types of time extensions: one for specific circumstances outside of the control of the owner or operator and the second aims to address situations where an emission reduction project falls outside of a turnaround window due to the permitting process. This subdivision establishes the criteria for time extensions, information that must be submitted, and the approval process.~~

~~Under paragraph (h)(1), an operator may request one 12-month extension for each unit for specific circumstances outside the control of the owner or operator. The operator should provide sufficient detail to explain the amount of time up to twelve months that is needed to complete the emission reduction project. If the operator requests less than 12 months, the Executive Officer will accept a subsequent request provided the total time for previous extensions plus subsequent requests does not exceed 12 months. Such a request must be made in writing no later than 90 days prior to the Compliance Date specified in the approved I-Plan. The owner or operator must demonstrate that there are specific circumstances that necessitate the additional time requested to complete the emission reduction project. The operator must provide sufficient information to document the operator took the necessary steps to ensure the project would not be delayed with a description and documentation of why the project was delayed. PR 1109.1 establishes four main areas that will be evaluated: Delays related to missed milestones; delays due to other agency approvals; delays related to delivery of parts or equipment; and delays related to workers or services.~~

~~For the second type of time extension, the amount of time allowed will be based on when the Permit to Construct was issued and the subsequent turnaround for the specific unit. An operator that requests a time extension for a turnaround under paragraph (h)(2) can also request a time extension under subparagraph (h)(1), provided the operator meets the criteria under that paragraph. The criteria for an extension for a turnaround are more specific and the operator must provide in writing at the time the permit application is submitted, the months and year(s) of the turnaround and the years for the subsequent turnaround. The Executive Officer will determine the time extension based on the current turnaround and the subsequent turnaround schedule. Other criteria are needed to ensure that in order to receive the extension, the issuance of the Permit to Construct~~

~~does not align with the turnaround window because of the amount of time between the permit application submittal and issuance of the Permit to Construct. Approval of a time extension for a turnaround is based on the criteria set forth under subparagraph (h)(2)(C). Staff will assess the information and work with the operator to establish the appropriate timeframe of the extension taking into account the current turnaround and the subsequent turnaround.~~

~~If there is additional information needed to substantiate the request for a time extension, the Executive Officer may request additional information. This provision is to allow the operator the opportunity to provide critical information needed to approve a time request. If the Executive Officer requests additional information, the operator must provide that information based on the timeframe specified by the Executive Officer. Approval of the time extension represents an amendment to the approved I-Plan, and the operators must adhere to the timeframe established in the approved time extension to meet the NOx and CO emission limit in PR 1109.1 Table 1, PR 1109.1 Table 2, approved B-Plan, or approved B-Cap. If the Executive Officer disapproves the time extension request, the applicable emission limits must be met within 60 calendar days after notification of disapproval is received.~~

~~Subdivision (i) – I-Plan, B-Plan, and B-Cap Submittal and Approval Requirements~~

~~ALTERNATIVE BARCT NOx LIMIT FOR PHASE I, PHASE II, OR PHASE III is the unit specific NOx concentration limit that is selected by the owner or operator to achieve the Phase I, Phase II, or Phase III Facility BARCT Emission Target in the aggregate in the B-Plan or B-Cap, where the NOx concentration limit will include the corresponding percent O_2 correction and determined based on the averaging time in Table 1 or subdivision (k), whichever is applicable.~~

~~PHASE I, PHASE III, OR PHASE III BARCT B-CAP ANNUAL EMISSIONS means the total NOx mass emissions remaining per Facility that incorporates BARCT Alternative NOx Limits for Phase I, Phase II, and Phase III, decommissioned units, and other emission reduction strategies to meet the respective Phase I, Phase II, or Phase III Facility BARCT Emission Targets in an I-Plan and are calculated pursuant to Attachment B of this rule.~~

~~PHASE I, PHASE II, OR PHASE III BARCT EQUIVALENT MASS EMISSIONS means the total NOx mass emissions remaining per Facility that incorporates respective BARCT Alternative NOx Limits for Phase I, Phase II, and Phase III in an approved B-Plan that are designed to meet the respective Phase I, Phase II, or Phase III Facility BARCT Emission Targets in an I-Plan and are calculated pursuant to Attachment B of this rule.~~

~~I-Plan, B-Plan, and B-Cap Submittal and Approval Requirements~~
~~This subdivision specifies the submittal, and review and approval requirements for the I-Plan, B--Plan, and B-Cap. Submittal requirements for the I-Plan, B-Plan, and B-Cap are provided in paragraphs (i)(1), (i)(2), and (i)(3), respectively.~~

~~B-Plan and B-Cap Submittal – Paragraphs I-Plan Submittal Requirements – paragraph (i)(1)~~
~~This paragraph includes the submittal requirements for facilities complying with an alternative schedule in the I-Plan~~

~~B-Plan and B-Cap Submittal Requirements – paragraphs (i)(2) and (i)(3)~~
~~Submitted B-Plan and B-Cap must meet specific criteria to be considered complete:~~

- ~~The device identification number and description,~~
- ~~Alternative BARCT NOx limits for each unit that will cumulatively meet the Facility BARCT Emission Target~~

~~For the purpose of B-Plan, the Alternative BARCT NOx limits is the concentration limit determined by the facility for each of the included units in the plan in a manner that the facility achieves the Facility BARCT Emission Target in aggregate. For the purpose of B-Cap, the Alternative BARCT NOx limits combined with other emission reduction strategies are used to determine the BARCT B-Cap Annual emissions.~~

~~For a B-Plan, the operator must demonstrate that the Phase I, Phase II, and Phase III BARCT Equivalent Mass Emissions is equal to or less than the respective Phase, I, Phase II, and Phase III Facility BARCT Emission Target. The BARCT Equivalent Mass Emissions for each facility is the total mass emissions at full implementation of control projects and must be calculated based on the Alternative BARCT NOx limits using the equations in Attachment B in PR 1109.1.~~

~~For a B-Cap, the operator must demonstrate that the Phase I, Phase II, and Phase III BARCT B-Cap Annual Emissions is equal to or less than the respective Phase, I, Phase II, and Phase III Facility BARCT Emission Target. The BARCT B-Cap Annual Emissions for each facility is the total mass emissions at full implementation of control projects and must be calculated based on the Alternative BARCT NOx limits and other emission reduction strategies as shown in Attachment B in PR 1109.1. Under a B-Cap, an owner or operator must achieve Alternative NOx Limits as well as demonstrate that the actual facility-wide emissions for all units in the B-Cap are at or below the Facility BARCT Emission Target. The unit specific emission limit is based on the averaging time specified in Table 1 for the applicable unit, however, the on-going compliance demonstration of facility-wide mass emissions are based on a rolling 365-day average, each day.~~

> ~~PHASE I, PHASE II, OR PHASE III FACILITY BARCT EMISSION TARGET means the total NOx mass emissions per Facility that must be achieved in an approved B-Plan or B-Cap that are based the percent reduction target of Phase I, Phase II, or if applicable, Phase III of an I-Plan option in Table 6 and are calculated pursuant to Attachment B of this rule.~~

~~Also, the owner or operator is required to demonstrate compliance with the previously approved I-Plan through using the equation specified under Attachment B of PR 1109.1 to show that the percent of emission reduction from either B-Plan or B-Cap is equal or more than the I-Plan Percent Reduction Targets for each phase per PR 1109.1 Table 4.~~

~~*I-Plan, B-Plan, and B-Cap Review and Approval Process – Paragraph (i)(4)*~~

~~Paragraph (i)(4) provides the review and approval/disapproval process for the I-Plan, B-Plan and B-Cap. The Executive Officer will review the submitted I-Plan to ensure the information required under subparagraphs (i)(1), (i)(2) and (i)(3) is complete and accurate for I-Plan, B-Plan and B-Cap, respectively. The key elements of the I-Plan are the Percent Reduction Targets by phase listed in Table 6 of PR 1109.1 and ensuring the emission reduction projects reflect the applicable NOx emission limits under PR 1109.1 Table 1, PR 1109.1 Table 2, an approved B-Plan or an approved B-Cap. For the B-Plan, the review ensures that the Facility BARCT Emission Target is met based on the Alternative BARCT NOx limits. The submitted B-Plan must demonstrate Equivalent Mass Emissions for included units cumulatively meets the Facility BARCT Emission Target that is adjusted by the Percent Reduction Targets based on the selected I-Plan option and the applicable Implementation Schedule in PR 1109.1 Table 6, using the calculation method provided in PR 1109.1 Attachment B. For the B-Cap, the review ensures the Facility BARCT Emission Target is met based on the Alternative BARCT NOx limits, shutdowns, and other reductions. Operators with a B-Cap also have an on-going compliance obligation to demonstrate that units in the approved B-Cap are below the Facility BARCT Emission Target. The submitted B-Cap must be prepared using the calculation method provided in PR 1109.1 Attachment B to demonstrate that Equivalent Mass~~

~~Emissions for included units cumulatively meets the Facility BARCT Emission Target less 10 percent and be adjusted by the Percent Reduction Targets based on the selected I-Plan option and the applicable Implementation Schedule in PR 1109.1 Table 6.~~

~~The plan approval will be contingent on including all of the required elements in the plans and the demonstration that the Percent Reduction Targets and Facility BARCT Emission Target will be met. If Executive Officer disapproves the initial I-Plan, B-Plan or B-Cap, the proposed rule considers a 30-day period for the owner or operator to resubmit a corrected plan. However, upon second disapproval of the plan by the Executive Officer, the owner or operator must comply with the emission limits in Table 1 or Table 2 of PR 1109.1 pursuant to the compliance schedule pursuant to paragraph (f)(1) which requires permit applications to be submitted for all units to comply with PR 1109.1 Table 1 by July 1, 2023 and requires the operator to meet the NOx and CO limits 36 months after the Permit to Operate is issued. An operator who is required to meet the compliance schedule under paragraph (e)(1), is not precluded from meeting NOx and CO limits in Table 2, provided the requirements under paragraph (d)(6) for the conditional NOx and CO limits were met.~~

~~Modification to an Approved I-Plan, Approved B-Plan, or Approved B-Cap – Paragraph (i)(5)~~
~~Paragraph (i)(5) includes the procedure the facilities must follow to apply for a modification to their approved I-Plan, B-Plan or B-Cap. In addition, PR 1109.1 includes requirements for when an I-Plan, B-Plan and B-Cap shall be modified:~~

- ~~A unit identified as meeting Table 2 no longer meets the requirements of subparagraph (d)(2)(A) or (d)(2)(B);~~
- ~~A unit in an approved B-Cap or B-Plan, identified as meeting Table 2 for establishing the Phase I, Phase II, or Phase III BARCT Facility Emission Target, is decommissioned;~~
- ~~A higher Alternative BARCT NOx Limit will be proposed in the South Coast AQMD permit application than the Alternative BARCT NOx Limit for that unit in the currently approved I-Plan, B-Plan, or B-Cap;~~
- ~~Any emission reduction project is moved to a later implementation phase, any emission reduction project is moved between phases, or any emission reduction project is removed from a phase; or~~
- ~~The owner or operator receives written notification from the Executive Officer that modifications to the I-Plan, B-Plan, or B-Cap are needed.~~

~~Review and approval of modifications to an I-Plan, B-Plan, or B-Cap shall be based the initial review and approval process. Although there is no specified timeframe to submit a modification, the owner or operator is expected to submit a modification upon knowing one of the items under paragraph (i)(5) are triggered.~~

~~Notification of Pending Approval of an I-Plan, B-Plan, or B-Cap – Paragraph (i)(6)~~
~~PR 1109.1 requires the Executive Officer to make the I-Plan, B-Plan, or B-Cap or modifications to an approved I-Plan, B-Plan, or B-Cap available to the public on the South Coast AQMD website 30 days prior to approval.~~

~~Subdivisions (j) and (k) – Requirements for CEMS and Source Testing~~
~~These subdivisions contain the requirements for the combustion equipment subject to PR 1109.1 that required to continuously monitor emissions with CEMS or conduct the source test.~~

~~For any unit that has a CEMS or the operator elects to use a CEMS to demonstrate compliance with the applicable PR 1109.1 NOx and CO limits, the installation and operation of CEMS must be in compliance with the applicable Rule 218.2 – Continuous Emission Monitoring System:~~

~~General Provisions and Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications.~~

~~For any unit with no CEMS, compliance with the applicable PR 1109.1 NOx and CO emission limits and percent of oxygen must be demonstrated by conducting a source test according to PR 1109.1 Table 7 or Table 8. The source test subdivision has two compliance schedules, one for unit with no ammonia in the exhaust (e.g., units without SCR) and one schedule for units with ammonia in the exhaust. PR 1109.1 requires an owner or operator of a unit that has air pollution control equipment with ammonia emissions in the exhaust to demonstrate compliance with the established ammonia emission limit in the permit to operate. Compliance must be demonstrated with an ammonia CEMS or through conducting an ammonia source test. The source test schedules in Tables 6 or 7 vary depending on the use of CEMS for the different pollutants being measures (e.g., NOx, CO or ammonia). The schedule requires source tests be conducted on a quarterly basis during the first 12 months of unit operation and thereafter. The frequency may change to annually when four consecutive quarterly source tests demonstrate compliance with the applicable ammonia limit. The quarterly source test schedule is effective as soon as any annual test is failed to demonstrate compliance.~~

~~If a unit does not operate a certified NOx or CO CEMS, source test must be conducted simultaneously for ammonia, NOx and CO. Conducting a NOx, CO, and ammonia source test simultaneous is important as the pollutants have an inverse relationship and it is critical that both pollutants are meeting the limits.~~

~~Below are the source test schedules for units with and without ammonia in the exhaust:~~

~~Table 2.4-8: PR 1109.1 Table 7 – Source Testing Schedule for Units without Ammonia Emissions in the Exhaust~~

~~**Combustion Equipment**~~	~~**Source Test Schedule**~~
~~Vapor Incinerators less than 40MMBtu/hr, Flares~~	• ~~Within 36 months from previous source test and every 36 months thereafter~~
~~All Other Units~~	
~~Units Operating without NOx or CO CEMS~~	• ~~Conduct source test simultaneously for NOx and CO within 12 months of being subject to Rule 1109.1 Emission Limit and quarterly thereafter~~ • ~~Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit if four consecutive quarterly source tests demonstrate compliance with the CO and NOx limit.~~ • ~~If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the NOx and CO emission limits prior to resuming annual source tests~~
~~Units operating with NOx CEMS and without CO CEMS~~	• ~~Conduct source test for CO within 12 months from previous source test and every 12 months thereafter~~
~~Units operating without NOx CEMS and with CO CEMS~~	• ~~Conduct source test for NOx during the first 12 months of being subject to Rule 1109.1 Emission Limit and quarterly thereafter~~ • ~~Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit if four consecutive quarterly source tests demonstrate compliance with the NOx emission limit.~~ • ~~If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the NOx emissions limits prior to resuming annual source tests~~

~~Table 2.4-9: PR 1109.1 Table 8 – Source Testing Schedule for Units with Ammonia Emissions in the Exhaust~~

~~Combustion Equipment~~	**~~Source Test Schedule~~**
~~Units operating without NOx, CO, or ammonia CEMS~~	• ~~Conduct source test simultaneously for NOx, CO, and ammonia quarterly during the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia permit limit and quarterly thereafter.~~ • ~~Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia permit limit if four consecutive quarterly source tests demonstrate compliance with the CO, NOx, and ammonia emission limit.~~ • ~~If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the NOx, CO, and ammonia emissions limits prior to resuming annual source tests.~~
~~Units operating with NOx CEMS and without CO and ammonia CEMS~~	• ~~Conduct source test for CO and ammonia quarterly during the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia permit limit and quarterly thereafter.~~ • ~~Source tests may be conducted annually after the first 12 months of being subject to Rule 1109.1 Emission Limit or ammonia permit limit if four consecutive quarterly source tests demonstrate compliance with the CO and ammonia emission limit.~~ • ~~If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the CO and ammonia emissions limits prior to resuming annual source tests.~~
~~Units operating with NOx and CO CEMS and without ammonia CEMS~~	• ~~Conduct source test for ammonia quarterly during the first 12 months of being subject to an ammonia permit limit and quarterly thereafter.~~ • ~~Source tests may be conducted annually after the first 12 months of being subject to an ammonia permit limit if four consecutive quarterly source tests demonstrate compliance with the ammonia emission limit.~~ • ~~If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the ammonia emissions limits prior to resuming annual source tests.~~
~~Units operating with NOx and ammonia CEMS and without CO CEMS~~	• ~~Conduct source test for CO within 12 months from previous source test for CO and every 12 months thereafter~~
~~Units operating with ammonia CEMS and without NOx or CO CEMS~~	• ~~Conduct source tests to determine compliance with NOx and CO emission limits pursuant to Table 7.~~

~~PR 1109.1 requires units that have not been source tested within the schedule in PR 1109.1 Table 7 or Table 8 to conduct a source test within six months from the date the unit implements PR 1109.1 emission limits for units greater than or equal to 20 MMBtu/hour and within 12 months from the date the unit was subject to a PR 1109.1 emission limits for units smaller than 20 MMBtu/hour. For a new or modified unit, the initial source test must be conducted within six months from commencing operation and afterward, pursuant to the applicable schedule in PR 1109.1 Table 7 or Table 8.~~

~~PR 1109.1 requires the owner or operator to submit the source test protocol, that includes an averaging time of no less than 15 minutes but no longer than 2 hours, to the South Coast AQMD Executive Officer for approval within 60 days after the Permit to Construct was issued or 60 days after being subject to a Rule 1109.1 Emission limit, unless otherwise approved by the Executive Officer and conduct the source test within 90 days after a written approval of the source test protocol. Moreover, the owner or operator must notify the Executive Officer at least one week prior to conducting a source test and provide the facility name and identification number, device identification number, and the source test date. Any source test conducted after the approval of the initial source test protocol does not require an approval if there is no change in the proposed rule or permit emission limits and the method of operation of the unit and the source test method has not changed since the initial source test, unless requested by the Executive Officer.~~

~~Upon approval of the source test protocol, the source test must be conducted using a South Coast AQMD approved contractor under the Laboratory Approval Program, using the applicable Averaging Time specified in Table 1 and based on at least one of the following test methods:~~

- ~~South Coast AQMD Source Test Method 100.1 – Instrumental Analyzer Procedures for Continuous Gaseous Emission Sampling; or~~
- ~~South Coast AQMD Source Test Method 7.1 – Determination of Nitrogen Oxide Emissions from Stationary Sources and South Coast AQMD Source Test Method 10.1 – Carbon Monoxide and Carbon Dioxide by Gas Chromatograph/Non-Dispersive Infrared Detector – Oxygen by Gas Chromatograph-Thermal Conductivity (GC/TCD);~~
- ~~District Source Test Method 207.1 – Determination of Ammonia Emissions from Stationary Sources; or~~
- ~~Any other test method determined to be equivalent and approved by the Executive Officer, and either the California Air Resources Board or the U. S. Environmental Protection Agency, as applicable.~~

~~The source test subdivision also includes the required averaging time for units that are required to demonstrate compliance with a PR 1109.1 emission limits based on a source test. All units that are not required to install and maintain CEMs must demonstrate compliance based on a 2-hour source test protocol.~~

~~Subdivision (l) – Diagnostic Emission Checks~~
~~This subdivision contains the requirements for diagnostic emission checks which is required for any unit performing a source test every 36 months. The provisions provide the protocol to conduct the diagnostic checks and the applicable schedule based on the corresponding source test schedule identified in Table 7 of PR 1109.1.~~

~~If emissions are measured in excess of an applicable PR 1109.1 emission limit or a permit condition using a diagnostic emissions check, this would not be considered a violation if an owner or operator corrects the problem and demonstrates compliance with the proposed rule using another diagnostic emissions check within 72 hours from the time they knew of excess emissions or shut down the unit by the end of an operating cycle.~~

~~Subdivision (m) – Monitoring, Recordkeeping, and Reporting Requirements~~
~~This subdivision contains the provisions for monitoring and recordkeeping for CEMS and source test records; diagnostic emission checks; startup and shutdown logs; the details of interest from either of the activity logs; and the required sequence of recordkeeping and reporting.~~

~~Units which are exempted from compliance with NOx and CO emission limits per PR 1109.1 are required to conduct monitoring, recordkeeping and reporting and the corresponding provisions (method and schedule) are included in this subdivision.~~

~~The owner or operator of a boiler or process heater less than 40 MMBtu/hour or a unit complying with a conditional limit in PR 1109.1 Table 2 is required to maintain records of burner replacement, including number of burners and date of installation. Recordkeeping will ensure compliance with the requirement that the owner or operator of a unit complying with a conditional limit in PR 1109.1 Table 2 must meet Table 1 emission limits upon replacement of the post-combustion equipment. Subdivision (m) includes provision requiring the owner to maintain records of the dates the existing post-combustion control equipment was installed or replaced.~~

~~Subdivision (n) – Exemptions~~
~~This subdivision includes provisions for specific combustion units which are exempted from compliance with NOx and CO emission limits under low-use, low-emitting, or operating under specific conditions. The following are the Rule 1109.1 exemptions.~~

~~Boilers and Process Heaters rated heat input capacity 2 MMBtu/hour or less – Paragraph (n)(1)~~
~~Small boilers and process heaters (less than or equal to 2 MMBtu per hour) used for comfort heating that are not used in processing units, are exempt from PR 1109.1. Small natural gas-fired water heaters, boilers, and process heaters (less than or equal to 2 MMBtu/hr) at PR 1109.1 facilities will be regulated under Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters regulate boilers and heaters.~~

~~Low-Use Boilers – Paragraph (n)(2)~~
~~Low-use boilers that are less than 40 MMBtu/hour and operated at less than 200 hours per calendar year are exempt from the emission limits in Table 1, Table 2, or an approved B-Plan. Low-use units have low emissions and high cost-effectiveness to retrofit. Facilities that elect to comply with a B-Cap must include the low-use units in the approved B-Cap and conduct source tests pursuant to Rule 1109.1 Table 7 or 8 and conduct diagnostic emission checks.~~

~~Low-Use Process Heaters – Paragraph (n)(3)~~
~~Low-use process heaters that are 40 MMBtu/hour or greater and fired at less than 15 percent of the rated heat capacity are exempt from the emission limits in Table 1, Table 2, or an approved B-Plan. Low-use units have low emissions and high cost-effectiveness to retrofit. Low-use units will still be subject to all of the other applicable provisions in the rule and must be included in an approved B-Cap and the interim emission limits.~~

~~*FCCU exemption provisions – Paragraphs (n)(4) and (n)(5)*~~
~~There are several exemption provisions for FCCUs. The first provision is to address boiler inspections required under California Code of Regulations, Title 8, Section 770(b). Some FCCUs with a CO boiler have to by-pass their SCR to safely conduct the inspection and without control an exemption from the emission is needed. For those units, PR 1109.1 provides an exemption from the applicable emission limits.~~

~~There is also an exemption for process heaters used to startup the FCCU provided the process heaters is operated for 200 hours or less per calendar year. Facilities that elect to comply with a B-Cap must include such process heater in the approved B-Cap and conduct source tests pursuant to Rule 1109.1 Table 7 or 8 and conduct diagnostic emission checks. The unit will have to accept a permit limit with a 200 hour per year operating limitation.~~

~~*Startup and Shutdown Boilers for Sulfuric Acid Plants - Paragraph (n)(6)*~~
~~Boilers used for startup and shutdown operations at a sulfuric acid plant are also low-use units that will be exempt from applicable emission limits and the CEMS requirements because to control would not be cost effective. The exemption is based on the current permit limitation which limits the boilers to 90,000 MMBtu of annual heat input per calendar year or less.~~

~~*Pilot Exemption for Boilers and Process Heaters – Paragraph (n)(7)*~~
~~The emission from boilers and process heater operating only the pilot during startup or shutdown are exempt from the applicable emission limits due to low emissions and not cost effective to control.~~

~~*Flare Exemptions – Paragraph (n)(8)*~~
~~Non-refinery flares that emit less than or equal to 550 pounds of NOx per year are exempt from the applicable emission limits provided the unit accepts a permit condition with a 550 pound of NOx per year limit. These units are not cost effective to control or replace at this time. Open flares are also exempt from the source test requirement; because there is no stack, these units cannot be source tested.~~

~~*Vapor Incinerator Exemptions – Paragraph (n)(9)*~~
~~Vapor incinerators also have a low-emitting exemption if they emit less than 100 pounds of NOx per year. These units are not cost effective to control or replace at this time.~~

~~**PR 1109.1 Attachment A – Supplemental Calculations**~~
~~This attachment includes calculations for the rolling average calculation for emissions data averaging and the interim NOx emission rate calculation and I-Plan Option 3 emission rate calculation for boilers and heaters greater than or equal to 40 MMBtu/hour or boilers and heaters less than 40 MMBtu/hour that operate with a certified CEMS.~~

~~**PR 1109.1 Attachment B – Calculation Methodology for the I-plan, B-plan, and B-cap**~~
~~This attachment includes calculations for the Baseline Emissions; Base Facility BARCT Emission Target; Phase I, Phase II, and Phase III Facility BARCT Emission Target; and Phase I, Phase II, and Phase III BARCT Equivalent Mass Emissions for a B-Plan and B-Cap.~~

~~**PR 1109.1 Attachment C – Facilities Emissions – Baseline and Targets**~~
~~Attachment C contains Baseline Facility Emissions as reported by the facilities with six or more units in their 2017 Annual Emissions Reports, or another year, as approved by the Executive Officer. PR 1109.1 Table C-1, presented in the table below, provides the Baseline Facility Emissions for the corresponding facilities subject to PR 1109.1.~~

~~Table 2.4-10: PR 1109.1 Table C-1 – Baseline Mass Emissions for Facilities with Six or More Units~~

~~Facility~~	~~Facility ID~~	~~Baseline Facility Emissions (2017) (tons/year)~~
~~AltAir Paramount, LLC~~	~~187165~~	~~28~~
~~Chevron Products Co.~~	~~800030~~	~~701~~
~~Lunday-Thagard Co. DBA World Oil Refining~~	~~800080~~	~~26~~
~~Phillips 66 Company/Los Angeles Refinery~~	~~171109~~	~~386~~
~~Phillips 66 Co/LA Refinery Wilmington PL~~	~~171107~~	~~462~~
~~Tesoro Refining and Marketing Co., LLC – Carson~~	~~174655~~	~~636~~
~~Tesoro Refining and Marketing Co., LLC – Wilmington~~	~~800436~~	~~674~~
~~Tesoro Refining and Marketing Co., LLC – Sulfur Recovery Plant~~	~~151798~~	~~8~~
~~Tesoro Refining and Marketing Co., LLC, Calciner~~	~~174591~~	~~261~~
~~Torrance Refining Company LLC~~	~~181667~~	~~899~~
~~Ultramar Inc.~~	~~800026~~	~~248~~
~~Valero Wilmington Asphalt Plant~~	~~800393~~	~~5~~

~~PR 1109.1 Attachment D – Units Qualifying for Conditional Limits in B-Plan and B-Cap~~

~~Attachment D of PR 1109.1 lists the units qualifying for conditional limits under a B-Plan or a B-Cap.~~

~~Table 2.4-11: PR 1109.1 Table D-1 – Units Qualifying for Conditional Limits in B-Plan~~

~~Facility ID~~	~~Device ID~~	~~Size (MMBtu/hr)~~
~~171109~~	~~D429~~	~~352~~
~~171109~~	~~D78~~	~~154~~
~~174655~~	~~D1465~~	~~427~~
~~174655~~	~~D419~~	~~52~~
~~174655~~	~~D532~~	~~255~~
~~174655~~	~~D63~~	~~300~~
~~181667~~	~~D1236~~	~~340~~
~~181667~~	~~D1239~~	~~340~~
~~181667~~	~~D231~~	~~60~~
~~181667~~	~~D232~~	~~60~~
~~181667~~	~~D234~~	~~60~~
~~181667~~	~~D235~~	~~60~~
~~181667~~	~~D950~~	~~64~~
~~800026~~	~~D1550~~	~~245~~
~~800026~~	~~D6~~	~~136~~
~~800026~~	~~D768~~	~~110~~
~~800030~~	~~D159~~	~~176~~
~~800030~~	~~D160~~	~~176~~
~~800030~~	~~D161~~	~~176~~
~~800030~~	~~D643~~	~~220~~

~~**Facility ID**~~	~~**Device ID**~~	~~**Size (MMBtu/hr)**~~
~~**800030**~~	~~D82~~	~~315~~
~~**800030**~~	~~D83~~	~~315~~
~~**800030**~~	~~D84~~	~~219~~
~~**800436**~~	~~D1122~~	~~140~~
~~**800436**~~	~~D384~~	~~48~~
~~**800436**~~	~~D385~~	~~24~~
~~**800436**~~	~~D388~~	~~147~~
~~**800436**~~	~~D388~~	~~147~~
~~**800436**~~	~~D770~~	~~63~~
~~**800436**~~	~~D777~~	~~146~~

~~**Table 2.4-12: PR 1109.1 Table D-2 – Units Qualifying for Conditional Limits in B-Cap**~~

~~**Facility ID**~~	~~**Device ID**~~	~~**Size (MMBtu/hr)**~~
~~**171107**~~	~~D220~~	~~350~~
~~**171107**~~	~~D686~~	~~304~~
~~**171109**~~	~~D429~~	~~352~~
~~**171109**~~	~~D78~~	~~154~~
~~**171109**~~	~~D79~~	~~154~~
~~**174655**~~	~~D33~~	~~252~~
~~**174655**~~	~~D419~~	~~52~~
~~**174655**~~	~~D421~~	~~82~~
~~**174655**~~	~~D532~~	~~255~~
~~**174655**~~	~~D539~~	~~52~~
~~**174655**~~	~~D570~~	~~650~~
~~**181667**~~	~~D1236~~	~~340~~

~~**Facility ID**~~	~~**Device ID**~~	~~**Size (MMBtu/hr)**~~
~~**181667**~~	~~D1239~~	~~340~~
~~**181667**~~	~~D231~~	~~60~~
~~**181667**~~	~~D232~~	~~60~~
~~**181667**~~	~~D234~~	~~60~~
~~**181667**~~	~~D235~~	~~60~~
~~**181667**~~	~~D920~~	~~108~~
~~**181667**~~	~~D950~~	~~64~~
~~**800026**~~	~~D1550~~	~~245~~
~~**800026**~~	~~D378~~	~~128~~
~~**800026**~~	~~D429~~	~~30~~
~~**800026**~~	~~D430~~	~~200~~
~~**800026**~~	~~D53~~	~~68~~
~~**800026**~~	~~D6~~	~~136~~
~~**800026**~~	~~D768~~	~~110~~
~~**800026**~~	~~D98~~	~~57~~
~~**800030**~~	~~D453~~	~~44~~
~~**800030**~~	~~D643~~	~~220~~
~~**800030**~~	~~D82~~	~~315~~
~~**800030**~~	~~D83~~	~~315~~
~~**800030**~~	~~D84~~	~~219~~
~~**800436**~~	~~D1122~~	~~140~~
~~**800436**~~	~~D158~~	~~204~~
~~**800436**~~	~~D250~~	~~89~~
~~**800436**~~	~~D33~~	~~252~~
~~**800436**~~	~~D384~~	~~48~~
~~**800436**~~	~~D385~~	~~24~~

~~Facility ID~~	~~Device ID~~	~~Size (MMBtu/hr)~~
~~800436~~	~~D386~~	~~48~~
~~800436~~	~~D387~~	~~71~~
~~800436~~	~~D388~~	~~147~~
~~800436~~	~~D770~~	~~63~~
~~800436~~	~~D777~~	~~146~~

Summary of PR 429.1

PR 429.1 was updated to clarify the purpose of the rule, include additional definitions, clarify definitions and rule provisions, update the startup and shutdown duration limits, reduce the frequency of scheduled startups, expand the types of activities subject to general duty requirements, update recordkeeping provisions to reflect current rule language, and add exemptions from startup and shutdown duration limits during commissioning, water freeing for a maximum of 24 hours, and when fuel is burned exclusively in a pilot light.

Subdivision (a) – Purpose

~~The purpose of this rule is to limit NOx emissions, while not increasing CO emissions, during periods of startup and shutdown, from units at petroleum refineries and facilities with related operations to petroleum refineries. PR 429.1 is needed to establish requirements during startup and shutdown pursuant to U.S. EPA policies to regulate startup, shutdown, and malfunction.~~ The purpose of this rule is to provide an exemption from Rule 1109.1 oxides of nitrogen (NOx) and carbon monoxide (CO) concentration limits and applicable rolling average provisions during startup, shutdown, commissioning, and certain maintenance events and establish requirements during startup, shutdown, and certain maintenance events to limit NOx and CO emissions. PR 429.1 is needed to establish requirements during startup and shutdown pursuant to U.S. EPA policies to regulate startup, shutdown, and malfunction.

Subdivision (b) – Applicability

PR 429.1 applies to an owner or operator of units at petroleum refineries and facilities with related operations to petroleum refineries. These facilities are subject to PR 1109.1.

Subdivision (c) – Definitions

PR 429.1 incorporates definitions from PR 1109.1 and source-specific rules to define types of facilities, equipment, and other rule terms. New or modified definitions added to PR 429.1 include:

- ~~SCHEDULED STARTUP means a planned startup that is specified by January 1 of each year.~~
- ~~SHUTDOWN means the time period that begins when an operator reduces load or heat input, and flue gas temperatures fall below the minimum operating temperature of the NOx post-combustion control equipment, if applicable, and which ends in a period of zero fuel flow or zero feedstock, or when combustion/circulation air flow ends if the unit does not use fuel for combustion.~~

- ~~STABLE CONDITIONS means that the fuel flow, fuel composition, or feedstock to a unit, or the combustion/circulation air if the unit does not use fuel for combustion, is consistent and allows for normal operations.~~

- CASTABLE REFRACTORY means refractory that is made by curing liquid material that has been poured into a mold.

This proposed definition describes a type of refractory and is used to distinguish the vapor incinerator categories in Table 1 (Table 2-1 in Staff Report). Castable refractory is harder than other types of refractory, such as a ceramic fiber catalyst, and takes longer to heat up as a result.

- CATALYST MAINTENANCE means conditioning, repairing, or replacing the catalyst in NOx post-combustion control equipment associated with a unit which has a bypass stack or duct that exists prior to [*Date of Adoption*].

This proposed definition describes the type of maintenance activities that are allowed pursuant to paragraph (d)(7). This definition specifies that only units which have a bypass stack or duct that exists prior to [*Date of Adoption*] may elect to use a bypass for the maintenance activities listed in the definition.

- CATALYST REGENERATION ACTIVITIES means the procedure where air or steam is used to remove coke from the catalyst of a unit or the conditioning of catalyst prior to the startup of a unit.

This proposed definition describes a maintenance activity that is exempt from paragraph (d)(2) of PR 429.1 in subparagraph (g)(1)(B). Staff received comments from operators which described times when a unit that contains catalyst may be required to undergo a catalyst regeneration. For example, a semi-regenerative rheniformer unit is a fixed-bed catalyst reactor system which accumulates carbon on the catalyst during the unit's operation. Over time, the carbon buildup reduces the catalyst's effectiveness and it requires that the unit be shutdown and the catalyst undergo a procedure to restore its activity. During this procedure, a unit, such as a furnace, may be used as a heat source to burn the carbon off of the catalyst.

In addition to regeneration activities, other catalyst systems may require steps to condition catalyst. For example, the sulfiding of a catalyst system requires the injection of a sulfur-containing reagent to temporarily reduce catalyst activity in preparation for the introduction of hydrocarbon feed to the unit. During the sulfiding of a catalyst system, a unit, such as a furnace, may be used as a heat source to assist with the decomposition of the sulfur-containing reagent.

Staff acknowledges that the activities in the regeneration or conditioning of catalyst systems as described in the preceding paragraphs and other similar activities constitute a unique occurrence where a unit, such as a furnace, is operated under abnormal conditions. The time to complete catalyst regeneration activities will not be counted towards PR 429.1 time allowances of a startup or shutdown.

- COMMISSIONING means the first commissioning of a unit, the first commissioning of NOx post-combustion control equipment, or electrical testing associated with upgrades or repairs of cogeneration gas turbines as required by North American Electric Reliability Corporation standards.

This proposed definition provides clarification on a type of activity that is exempt from PR 1109.1 NOx and CO concentration limits and applicable rolling average provisions pursuant to paragraph (d)(1) and exempt from the requirements in paragraph (d)(2).

- FEED RATE means the total input of any petroleum derivative feedstock stream to a process unit.

This proposed definition provides clarification for compliance determination with subparagraph (d)(7)(C). The feed rate includes the total input of any petroleum derivative feedstock, which includes fresh feed and recycled feed.

- MINIMUM OPERATING TEMPERATURE means the minimum operating temperature specified by the manufacturer, unless otherwise defined in the South Coast AQMD Permit to Construct or Permit to Operate.

This proposed definition provides clarification on the temperature described for compliance determination in various PR 429.1 requirements.

- NEW FACILITY means a facility that begins operation after [*Date of Adoption*].

This definition describes a type of facility that PR 429.1 is applicable to.

- NOx POST-COMBUSTION CONTROL EQUIPMENT means air pollution control equipment which eliminates, reduces, or controls the issuance of NOx after combustion.

This definition is modified from the Rule 102 – Definition of Terms definition of CONTROL EQUIPMENT and made specific to NOx and post-combustion control equipment.

- REFRACTORY DRYOUT means the initial application of heat under controlled rates to safely remove water from refractory lining as part of the curing process prior to placing the unit in service.

This proposed definition describes a process that is exempt from PR 429.1 from paragraph (d)(2) of PR 429.1 in subparagraph (g)(1)(A).[1]

- SCHEDULED STARTUP means a planned startup that is specified by January 1 of each year.

This definition was modified from the definition of A SCHEDULED START-UP AND SHUTDOWN PAIR in Rule 429. Scheduled startup events include, but are not limited to, those planned for maintenance, testing, tuning, or construction. A startup is only considered a scheduled startup if it is specified by January 1 each year. Scheduled startups do not include change in status due to demand loads, unplanned maintenance, breakdowns, malfunctions, or other events not scheduled prior to January 1 for the upcoming calendar year.

- SHUTDOWN means the time period that begins when an operator reduces load or heat input, and flue gas temperatures fall below the minimum operating temperature of the NOx post-combustion control equipment, if applicable, and which ends in a period of zero fuel flow or zero feedstock, or when combustion/circulation air flow ends if the unit does not use fuel for combustion.

This proposed definition is from Rule 1134 and was modified to apply to all equipment types subject to PR 429.1.

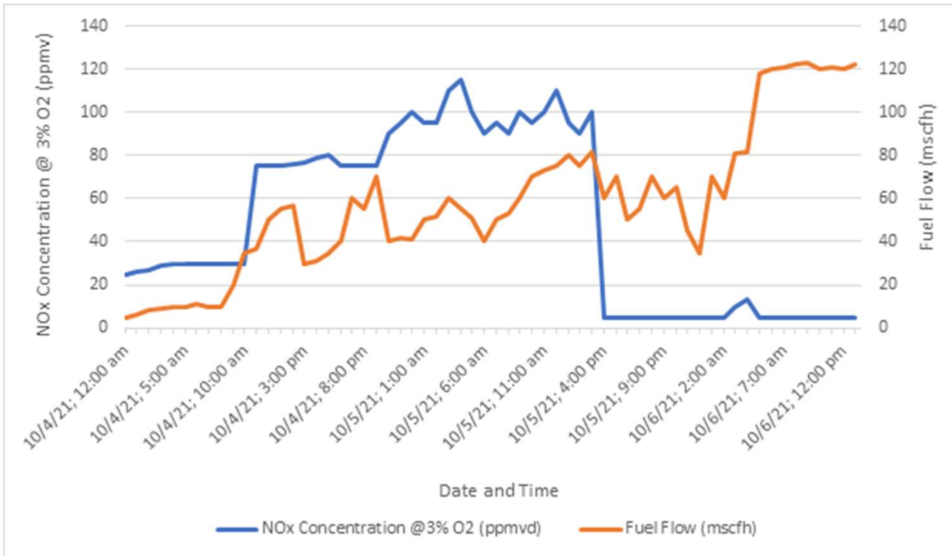
- STABLE CONDITIONS means that the fuel flow, fuel composition, or feedstock to a unit, or the combustion/circulation air if the unit does not use fuel for combustion, is consistent and allows for normal operations.

This proposed definition provides clarification for compliance determination under subparagraph (d)(2)(A), as well as the definition of startup. For example, a stakeholder expressed concern that during the startup of a hydrogen reformer furnace, there is an adjustment period where the fuel balance fluctuates and is unstable. Once the fuel balance normalizes, the unit is considered to be under stable conditions. A unit may stabilize and destabilize multiple times during a complex startup procedure. Stable conditions are only determined after all startup procedures for a unit are complete.

Staff provides an example of when evaluating the time stable conditions are met is essential for determining compliance with the startup and shutdown duration limits specified in paragraph (d)(2) (Figure 2.4-1). This example was created by staff for clarification purposes and is not based on actual CEMS data. This example is for a process heater equipped with NOx post-combustion control equipment, which has a startup duration limit of 48 hours.

In this example, startup begins on October 4, 2021, at 12:00 am. On October 5, 2021, at 4:00 pm the flue gas temperature reaches the minimum operating temperature of the NOx post-combustion control equipment, the NOx post-combustion equipment begins operating, and the Rule 1109.1 NOx concentration limit of 5 ppmv is met. The process heater took 40 hours to reach the minimum operating temperature of the NOx post-combustion control equipment and meet Rule 1109.1 concentration limits. The process heater continues to meet the 5 ppmv NOx concentration limit until October 6, 2021 at 3:00 am, where it is exceeds the concentration limit for 2 hours, before meeting 5 ppmv NOx again on October 6, 2021 at 5:00 am when fuel flow stabilizes. In this example, the process heater used 42 hours of the 48-hour startup duration limit specified in paragraph (d)(2) and is in compliance with paragraph (d)(2). The 11 hours that the unit was meeting the Rule 1109.1 concentration limit before reaching stable fuel flow is not counted towards the startup duration limit pursuant to paragraph (d)(2).

Figure 2.4-1 – Startup Example for Process Heater with NOx Post-combustion Control Equipment



- STARTUP means the time period that begins when a NOx emitting unit combusts fuel, after a period of zero fuel flow or zero feedstock, or when combustion/circulation air is introduced if the unit does not use fuel for combustion, and ends when the flue gas temperature reaches the minimum operating temperature of the NOx post-combustion control equipment and the unit reaches stable conditions, or when the time limit specified in Table 1 is reached, whichever is sooner.

This proposed definition is from Rule 1134 and was modified to apply to all equipment types subject to PR 429.1. Staff worked with stakeholders to address concerns about when startup ends for a unit equipped with NOx post-combustion control equipment and units without NOx post-combustion control equipment.

Stakeholders expressed that although NOx post-combustion control equipment needs to reach the minimum operating temperature for startup, there are additional steps, such as the injection of any associated chemical reagent, before NOx and CO concentration limits can be achieved. Stakeholders also expressed that there are unique situations, such as the startup of a hydrogen reformer furnace, where the introduction of varying quality of gas fuel from the routing of gas to the furnace burners may cause compositional fluctuations where the control of the post-combustion control equipment is not stable. Therefore, startup is not considered to be complete until a unit reaches the minimum operating temperature of the NOx post-combustion control equipment and the unit reaches stable conditions, or the duration limit specified in Table 1, whichever is sooner. For units without NOx post-combustion control equipment, startup ends when the duration limit in Table 1 is achieved, notwithstanding the requirements of subparagraph (d)(2)(A).

One operator expressed concern with compliance and the time allotted for an FCCU startup where only combustion/circulation air is used to move catalyst prior to the startup of the unit and there are no products of combustion being produced. In this example, if no combustion is occurring where fuel is not being injected into the regenerator to initiate or sustain the heat up of the catalyst, then the relief set by PR 429.1 is not needed for this amount of time for this activity nor is the time to be deducted from the amount of time of relief established in PR 429.1.

- TUNING means adjusting, optimizing, rebalancing, or other similar operations to a gas turbine or an associated control device or otherwise as defined in a South Coast AQMD Permit to Construct or Permit to Operate. Tuning does not include normal operations to meet load fluctuations.
- This definition is from Rule 1134 and modified to include South Coast AQMD Permits to Construct.
- UNIT means equipment that is subject to Rule 1109.1 which includes boilers, flares, fluid catalytic cracking units (FCCUs), gas turbines, petroleum coke calciners, process heaters, steam methane reformer heaters, sulfuric acid furnaces, sulfur recovery units/tail gas incinerators (SRU/TG incinerators), and vapor incinerators, as defined in Rule 1109.1, requiring a South Coast AQMD Permit to Operate and not required to comply with a NOx emission limit by other South Coast AQMD Regulation XI rules.

This definition is from PR 1109.1 and modified to refer to definitions in PR 1109.1.

- WATER FREEING means the procedure of gradually heating a unit to vaporize and remove any accumulated or condensed water in the unit during startup.

This proposed definition describes an activity that is exempt from paragraph (d)(2) of PR 429.1 in subparagraph (g)(1)(D)[2]. Staff received comments from operators, that process heaters, such as FCCU feed pre-heaters, coker heaters, and crude unit heaters and associated equipment, may contain accumulated or condensed water which needs to be gradually boiled off so that the unit may be safely started up.

Subdivision (d) – Requirements

Exemption from Rule 1109.1 Concentration~~Emission~~ Limits During Startup, Shutdown, Commissioning and Certain ~~Catalyst~~ Maintenance Events

Paragraph (d)(1) specifies that NOx and CO ~~emission~~concentration limits and the applicable rolling average provisions pursuant to Rule 1109.1 do not apply during startup, shutdown, commissioning, and ~~catalyst~~certain maintenance events. During startup, shutdown, ~~commissioning,~~ and ~~catalyst~~certain maintenance events, an owner or operator of a unit is subject to the provisions in PR 429.1.

Startup and Shutdown Duration Limits

Paragraph (d)(2) includes PR 429.1 Table 1, which contains the startup and shutdown duration limits for units at former RECLAIM facilities~~petroleum refineries~~ and new facilities~~petroleum refineries~~. Startup and shutdown duration limits only apply when a unit exceeds the applicable NOx or CO concentration limits in PR 1109.1. During the startup or shutdown of a unit, exhaust emission concentrations may fluctuate due to the nature of startups and shutdowns. Therefore, the time counted towards the startup and shutdown duration limits in PR 429.1 may be non-continuous. A unit may meet the applicable NOx and CO emission limits in PR 1109.1 temporarily

[2] https://brimstone-sts.com/wp-content/uploads/2015/11/04V11-Jenkins-Considerations-for-Refractory-Dryouts.pdf

during a startup or shutdown but then experience swings where the applicable ~~emission~~concentration limits are not met due to instability. The time counted towards Table 1 duration limits does not start anew if PR 1109.1 emission limits are temporarily met during the startup or shutdown, but then fluctuations result in an emission increase which exceeds applicable PR 1109.1 ~~emission~~concentration limits. However, in a situation where the owner or operator of a unit has initiated a startup of a unit but then had to shutdown the unit and will startup the unit again, then the PR 429.1 Table 1 duration limits would apply anew. A unit with permit conditions which specifies more stringent startup or shutdown duration limits than PR 429.1 will continue to be restricted by its existing permit conditions.

Table 2.4-~~13~~15: PR 429.1 Table 2-1
Startup and Shutdown Duration Limits

Unit Type	Time Allowance When Emissions Exceed Rule 1109.1 Emission Limits (Hours)
Boilers and ~~Process Heaters~~Gas Turbines without NOx Post-Combustion Control Equipment, ~~Gas Turbines,~~ Flares, Vapor Incinerators without NOx Post-Combustion Control Equipment or Castable Refractory	2
Gas Turbines with NOx Post-Combustion Control Equipment	4
Vapor Incinerators with NOx Post-Combustion Control Equipment, Vapor Incinerators with Castable Refractory	20
Process Heaters without NOx Post-Combustion Control Equipment	24
Boilers and Process Heaters with NOx Post-Combustion Control Equipment, Steam Methane Reformer Heaters, Sulfuric Acid Furnaces	48
Steam Methane Reformers with Gas Turbine	60
FCCU Feed Pre-Heater	90
FCCUs, Petroleum Coke Calciners, SRU/TG Incinerators	120

Startup and shutdown duration limits were established through an assessment which considered duration limits established in permits, the general startup and shutdown time periods necessary for each equipment category, and individual startup and shutdown data for outliers.

Best Management Practices

Best management practices are contained in subparagraph (d)(2)(A) ~~pursuant to the U.S. EPA 2020 SSM SIP Policy~~. If a unit reaches stable conditions and reaches the minimum operating temperature of the NOx post-combustion control equipment, if applicable, before reaching the duration limit specified in PR 429.1 Table 1, the startup period is considered to be over, and the unit is required to meet applicable NOx and CO ~~emission~~concentration limits in PR 1109.1. Stable conditions and minimum operating temperature are defined in PR 429.1. Subparagraph (d)(2)(A) will further limit excess emissions from startup events.

Limit to the Number of Scheduled Startups

Paragraph~~s~~ (d)(3)~~ and (d)(4)~~ limits the number of scheduled startups. Limitations to the number of scheduled startups is an existing requirement in Rule 429 and is carried forward into PR 429.1. Furthermore, limiting the frequency of scheduled startups provides further bounds to the startup and shutdown provisions. Unscheduled startups are not limited by PR 429.1 because they may be driven by operational demand, emergencies, or maintenance needs.

Paragraph (d)(3) limits the number of scheduled startup events to 10 per calendar year for ~~boilers, flares,~~cogeneration gas turbines~~, process heaters, steam methane reformer heaters, sulfuric acid furnaces, and vapor incinerators~~. Process Heaters on Delayed Coking Units are limited to 5 scheduled startup events per calendar year. All other units~~ equipment~~ are limited to 2 scheduled startups per year. ~~This maximum number of scheduled startup events reflects Rule 429 requirements for a scheduled startup and shutdown pair for equipment subject to Rule 1109.~~

~~Paragraph (d)(4) limits the number of scheduled startup events to 3 per calendar year for FCCUs, petroleum coke calciners, and SRU/TG incinerators. The maximum number of scheduled startups for FCCUs, petroleum coke calciners, and SRU/TG incinerators is fewer than other equipment categories due to the longer startup and shutdown durations allowed pursuant to Paragraph (d)(2).~~

General Duty Requirements

Paragraph (d)(~~5~~4) was modified from an existing Rule 429 provision and requires that an owner or operator of a unit at a former RECLAIM facility~~petroleum refinery~~ or a new facility~~petroleum refinery~~ that exceeds applicable PR 1109.1 NOx and CO ~~emission~~concentration limits during startup, shutdown, maintenance for units with a South Coast AQMD Permit to Operate condition before [*Date of Adoption*] which allows the use of a bypass to conduct maintenance, catalyst maintenance, tuning, and commissioning ~~startup and shutdown events~~ to take all reasonable and prudent steps to minimize emissions to meet applicable concentration~~emission~~ limits. Reasonable and prudent steps to minimize emissions include, but are not limited to, equipment repairs and adjusting the temperatures of post-combustion controls.

Requirements for Units with NOx Post-Combustion Control Equipment

Paragraph (d)(~~6~~5) requires each unit equipped with NOx post-combustion control equipment to install and maintain a temperature measuring device that is calibrated annually at the inlet of the NOx post-combustion control equipment. Temperature measuring devices include thermocouples and temperature gauges. Most existing units with NOx post-combustion control equipment are already equipped with temperature measuring devices. It is standard practice to include a temperature measuring device requirement for units with NOx post-combustion control equipment in South Coast AQMD permits, and any future units would be expected to install and maintain a temperature measuring device through the permitting process. A temperature measuring device is necessary to determine the temperature of the gas stream entering the NOx post-combustion control equipment and when the catalyst in the NOx post-combustion control equipment will effectively control NOx emissions.

NOx Post-Combustion Control Equipment Operating Temperature

Paragraph (d)(~~7~~6) requires the operation of NOx post-combustion control equipment during startup and shutdown events, including the injection of any associated chemical reagent into the exhaust stream to control NOx, if the temperature of the gas to the inlet of the emission control system is greater than or equal to the minimum operating temperature and the temperature is stable. Minimum operating temperature is defined in PR 429.1. ~~A unit with a permit condition specifying a lower temperature to operate its NOx post-combustion control equipment than PR 429.1 will continue to be restricted by its existing permit condition.~~

Catalyst Maintenance Provision

Paragraph (d)(~~8~~7) specifies requirements for an owner or operator of a unit at a former RECLAIM facility~~petroleum refinery or a new petroleum refinery~~ that elects to use a bypass to conduct catalyst maintenance. Only units which have a bypass stack or duct that exists prior to *[Date of Adoption]* may elect to use a bypass to conduct catalyst maintenance. Catalyst used in NOx post-combustion control equipment at petroleum refineries and at facilities with related operations to petroleum refineries typically needs to be replaced every 3-6 years, which is shorter than the turnaround schedules for some units. The process of starting up and shutting down units to conduct maintenance on NOx post-combustion control equipment can result in more emissions than if the NOx post-combustion control equipment were bypassed temporarily and the unit was kept in operation. This provision is only for units that are equipped with a stack or ducting that allows for bypassing the unit's NOx post-combustion control equipment by [*Date of Adoption*]. If a permit contains more stringent requirements than PR 429.1, the more stringent permit requirements will continue to be applicable.

Subparagraph (d)(~~8~~7)(A) precludes the use of a bypass to conduct catalyst maintenance for units that are scheduled to operate continuously for less than five years between planned maintenance shutdowns of the unit. Subparagraph (d)(7~~8~~)(A) is included to limit the catalyst maintenance provision to units that have long turnaround schedules. Turnarounds typically occur every 3-5 years for refinery equipment, but some units have turnaround schedules that are 9 years or longer.

Subparagraph (d)(~~8~~7)(B) limits the use of a bypass to condition, repair, or replace the catalyst in the NOx post-combustion control equipment to 200 hours in a rolling three-year cycle. Therefore, a catalyst used in NOx combustion control equipment could be conditioned, repaired, or replaced every three years under subparagraph (d)(~~8~~7)(B). Three years is a conservative estimate of catalyst life; catalysts typically need to be replaced every 3-6 years.

Subparagraph (d)(~~8~~7)(C) specifies that the unit must be operated at ~~the minimum safe operating~~50% of the feed rate of the process unit of less when the NOx post-combustion control equipment is bypassed. Feed rate is defined in PR 429.1. Staff established the percentage of feed rate based on information provided by stakeholders of minimum safe operating rates. Subparagraph (d)(~~8~~7)(C) is included to reduce emissions by lowering the rate the unit is operating at when using a bypass to conduct catalyst maintenance.

Subparagraph (d)(~~8~~7)(D) ~~requires documentation from the manufacturer of the minimum safe operating rate of the unit being bypassed to be submitted the South Coast AQMD to assist in verifying compliance with subparagraph (d)(8)(C)~~ provides notification requirements during catalyst maintenance. Notifications are required to be made by calling to 1-800-CUT-SMOG at least 24 hours before bypassing the NOx post-combustion control equipment and include the date, estimated time, and estimated duration that the NOx post-combustion control equipment will be bypassed. Advanced notification of these events is considered important because it gives the South

Coast AQMD time to allocate resources if necessary to monitor the catalyst maintenance activity and information to respond to inquiries from the community should they arise.

~~Subparagraph (d)(8)(E) provides notification requirements during catalyst maintenance. Notifications are required to be made by calling to 1-800-CUT-SMOG at least 24 hours before bypassing the NOx post-combustion control equipment and include the date and estimated time and estimated duration that the NOx post-combustion control equipment will be bypassed. Advanced notification of these events is considered important because it gives the South Coast AQMD time to allocate resources if necessary, to monitor the catalyst maintenance activity and information to respond to inquiries from the community should they arise.~~

Subparagraph (d)(~~8~~7)(~~F~~E) contains a requirement to continuously monitor NOx and CO emissions during catalyst maintenance. PR 429.1 only requires NOx and CO emissions to be continuously monitored when the owner or operator elects to bypass the NOx post-combustion control equipment to conduct catalyst maintenance. The continuous monitoring is required to be conducted with a certified Continuous Emissions Monitoring System (CEMS) pursuant to Rule 218.2 – Continuous Emission Monitoring System: General Provisions and Rule 218.3 – Continuous Emission Monitoring System: Performance Specifications or a contractor approved under the South Coast AQMD Laboratory Approval Program (LAP) if emissions cannot be monitored be a certified CEMS.

Paragraph (d)(~~8~~7) is intended only for activities involved in catalyst maintenance, as described in in subdivision (c). This provision is not intended to provide relief for malfunctions or breakdowns of ancillary equipment used in the operation of NOx post-combustion control equipment. In situations not related to the conditioning, repairing, or replacement of catalyst in NOx post-combustion control equipment, but related to breakdowns of ancillary equipment used in the operation of the NOx post-combustion equipment, paragraph (d)(~~8~~7) does not apply. South Coast AQMD Rule 430 – Breakdown Provisions (Rule 430), provides relief from of rules or permit conditions during breakdowns during specific conditions.

Subdivision (e) – Notification

Paragraph (e)(1) provides notification requirements for scheduled startups. Notifications are required to be made by calling 1-800-CUT-SMOGat least 24 hours before the scheduled startup and include the date and time of the scheduled startup. Advanced notification of these events is considered important because it gives the South Coast AQMD time to allocate resources if necessary, to monitor the startup and information to respond to inquiries from the community should they arise.

Subdivision (f) – Recordkeeping

Records assist in verifying compliance with Rule 429.1. Paragraph (f)(1) provides recordkeeping requirements for owners and operators of units at a former RECLAIM facility~~petroleum refinery~~ or a new facility~~petroleum refinery~~. Records are required to be maintained on-site for 5 years and made available to the South Coast AQMD upon request. The provision in subparagraph (f)(1)(A) requires the operating log to contain the date, time, duration, and reason for each startup, shutdown, refractory dryout, catalyst maintenance, catalyst regeneration activity, ~~-~~tuning, commissioning, and water freeing event.~~initial commissioning of a unit, and initial commissioning of NOx post-combustion control equipment~~. For startups, the reason provided in the operating log must specify if the startup was scheduled. Subparagraphs (f)(1)(B) through (f)(1)(D) requires a list of scheduled startups, a list of planned maintenance shutdowns for the next 5 years for each unit equipped with a bypass stack or duct that exists prior to [*Date of Adoption*], and NOx and CO emissions data collected pursuant to subparagraph (d)(~~8~~7)(~~F~~E).

Paragraph (f)(2) requires an owner or operator of a unit at a former RECLAIM facility~~petroleum refinery~~ or a new facility~~petroleum refinery~~ equipped with NOx post-combustion control equipment to maintain documentation from the manufacturer of the minimum operating temperature of the NOx post-combustion control equipment. Records are required to be on-site and made available to the South Coast AQMD upon request for compliance verification.

Subdivision (g) – Exemptions

Paragraph (g)(1) exempts units from the startup and shutdown duration limits contained in paragraph (d)(2) during refractory dryouts, catalyst regeneration activities,~~-~~ commissioning, and a maximum of 24 hours for water freeing a unit ~~the initial commissioning of a unit, and the initial commissioning of NOx post-combustion control equipment~~. Temperatures are not high enough for NOx post-combustion control equipment to be effective during refractory dryouts, ~~or~~ catalyst regeneration activities, and water freeing~~dryouts~~. Furthermore, refractory dryouts and catalyst regeneration activities are infrequent processes during which the expected mass emissions of NOx are low. The expected mass emissions during water freeing are also low and stakeholders expressed that there are significant safety issues associated with starting up too quickly without properly removing condensed water from the unit. The safety issues include concern of the potential rapid vaporization of liquid water in parts of the unit where such a large volume expansion may damage equipment. The exemption from startup and shutdown duration limits during water freeing is limited to 24 hours. The initial commissioning of a unit or the initial commissioning of NOx post-combustion control equipment only occurs once, and specific conditions are established by South Coast AQMD's Engineering and Permitting Division for this time period. ~~Stakeholders had expressed concern that initial commissioning activities may present periods of time where a new unit or a new NOx post-combustion control equipment would experience one-time, unique issues, and may be unable to meet the startup and shutdown duration limits in paragraph (d)(2)~~ Electrical testing for cogeneration turbines is required by the North American Electric Reliability Corporation, and specific conditions will be required by South Coast AQMD's Engineering and Permitting Division.~~.~~

Paragraph (g)(2) exempts units equipped with a NOx post-combustion control equipment from the catalyst maintenance requirements in paragraph (d)(~~8~~7) if the unit has a permit condition before [*Date of Adoption*] that allows the use of a bypass for maintenance. A unit that qualifies for the exemption in paragraph (g)(2) will continue to be restricted by its current permit conditions.

Paragraph (g)(3) exempts units burning fuel exclusively in a pilot light from the startup and shutdown duration limits contained in paragraph (d)(2) and recordkeeping requirements specified in paragraph (f)(1). Fuel burned in a pilot light contributes relatively minimal emissions and is not the primary NOx emission source in combustion equipment.

Summary of PAR 2005

No changes to PAR 2005 have been made since the release of the Draft SEA.

Currently, all new or modified sources at a RECLAIM facility with an emission increase of a RECLAIM pollutant are subject to BACT under Rule 2005 subparagraph (c)(1)(A). The proposed provision in PAR 2005 paragraph (c)(5) allows a RECLAIM facility, installing add-on air pollution control equipment to comply with a command-and-control NOx emission limit for a

Regulation XI rule, to apply the BACT requirement for a SOx emission increase under Rule 1303 paragraph (a)(1) instead of BACT under Rule 2005 subparagraph (c)(1)(a). RECLAIM facilities electing to meet the BACT requirement under Rule 1303 can use the limited BACT exemption in PAR 1304 subdivision (f) if the new or modified source meets the criteria specified in PAR 1304 subparagraphs (f)(1)(A) through (E).

Although these are RECLAIM facilities, these new or modified sources are subject to a Regulation XI rule as part of transitioning the RECLAIM program to a command-and-control regulatory structure. Therefore, these new or modified sources may be regulated under the command-and-control BACT provision in Regulation XIII. Regulating these sources under Regulation XIII is necessary to allow the use of the limited BACT exemption in PAR 1304, since the PM_{10} and/or SOx emission increases from the new or modified sources are a result of a NOx rule in Regulation XI.

Summary of PAR 1304

Since the release of the Draft SEA, PAR 1304 was updated to clarify in subparagraph (f)(1)(E) that a mass balance calculation can be used to calculate the increase in PM emissions for the purpose of determining federal major NSR applicability. Other portions of the following summary have been revised for consistency to reflect recent updates made in the Draft Staff Report for PAR 1304.

Subparagraph (f)(1)(A)

PAR 1304 subparagraph (f)(1)(A) limits the BACT exemption to new or modified permit units being installed or modified at RECLAIM or former RECLAIM facilities to comply with a NOx BARCT rule to transition the NOx RECLAIM program to command-and-control regulatory structure. Qualifying projects undertaken to meet conditional NOx Concentration Limits and Alternative BARCT NOx Limits, such as concentration NOx limits for a B-Plan or B-Cap, for PR 1109.1 may use the limited BACT exemption. Conditional NOx Concentration Limits and Alternative BARCT NOx Limits are considered NOx BARCT emission limits specified in PAR 1304 subparagraph (f)(1)(A). The NOx BARCT limits must have been initially established before December 31, 2023. The BACT exemption ~~and~~ will not apply to future BARCT rules with new limits initiated after~~. The~~ December 31, 2023. Although the cutoff date excludes using ~~this~~ the BACT exemption for future BARCT rules, the BACT exemption would apply to NOx BARCT limits that are later revised if they were initially established before December 31, 2023. ~~Pending~~ Additionally, projects with applications that ~~have not been~~ were not deemed complete prior to the September 1, 2021 ~~p~~Public W~~w~~orkshop for PAR 1304 and that were~~are~~ needed to comply with a NOx BARCT standard established as part of the NOx RECLAIM transition qualify for the BACT exemption.

Subparagraph (f)(1)(B)

The proposed provision under PAR 1304 subparagraph (f)(1)(B) limits the BACT exemption to projects that have no increase in the cumulative total maximum rated capacity. The maximum rated capacity is based on the allowable permitted heat input capacity of the permit unit(s). However, if a maximum rated capacity is not specified on a permit, then the maximum rated capacity is based on the physical design capacity or the capacity specified on the nameplate of a combustion unit. Replacement projects with a variable number of units being replaced would be allowed under PAR 1304 subparagraph (f)(1)(B) as long as the post-project cumulative total maximum rated capacity does not exceed the pre-project cumulative total maximum rated capacity for the existing unit(s). A single unit can be replaced with one or more units or multiple units can be replaced with one or more units, as long as there is no increase in the cumulative total maximum rated capacity of the existing unit(s) being replaced and the replacement(s) serve the same purpose. The criteria to require that a replacement serve the same purpose as the unit being replaced was developed according to the definition for a replacement unit under federal NSR.[3] Under federal NSR, to be considered a replacement, a unit must be reconstructed[4] or completely take the place of an existing unit, be identical to or functionally equivalent[5] to the replaced unit, not alter the basic design parameters[6] of the process unit being replaced, and be replacing a unit that is permanently removed, disabled, or barred from operation by an enforceable permit. Replacements that meet the criteria under federal NSR can be considered an existing emissions unit[7] for the purpose of determining federal major NSR applicability. NSR applicability for an existing emissions unit uses a Baseline Actual-to-Projected-Actual test where the baseline actual emissions are based on the pre-project emissions.[8]

The PAR 1304 BACT exemption can be used for situations where a unit will be replaced with a new unit from a different source category (e.g., a boiler for a turbine). If the new unit is installed to meet a NOx BARCT limit and serves the same purpose, then the BACT exemption will not be restricted to require that the new unit be of the same source category. Units from different source categories that might "serve the same purpose" would not have the same basic design parameters and therefore would not meet the federal definition for a replacement. A unit being replaced with a unit from a different source category would then be considered a new emissions unit rather than a replacement unit, which is an existing emissions unit under federal NSR, since the unit would not meet the federal definition for a replacement. For a new emissions unit, federal major NSR applicability is determined using a Baseline Actual-to-Potential test where the baseline emissions are zero. As compared to an existing unit, and replacements that meet the federal definition for replacement, may use the Baseline Actual-to-Projected-Actual test and the pre-project emissions as the baseline emissions. If the unit treated as a new unit qualifies as a major modification, then it would not be able to use the BACT exemption in PAR 1304.

PAR 1304 subparagraph (f)(1)(B) also includes a provision to avoid extended delays during equipment replacement by limiting simultaneous operations of new or modified permit unit(s) with the equipment being replaced to a maximum of 90 days, which is consistent with the startup period allowed in division (d) of Rule 1313 – Permits to Operate.

Subparagraph (f)(1)(C)

The proposed provision in PAR 1304 subparagraph (f)(1)(C) is to ensure there is no increase in the physical or operation design capacity for the entire facility, except for the changes needed for the new or modified permit unit(s) that meet the criteria of PAR 1304 subparagraph (f)(1)(B). This provision differs from PAR 1304 subparagraph (f)(1)(B) which specifies the criteria to ensure there is no increase in the cumulative total maximum rated capacity for the new or modified

[3] 40 CFR 51.165(a)(1)(xxi) and 40 CFR 52.21(b)(33) defined replacement unit

[4] A reconstructed unit as defined in 40 CFR 60.15(b)

[5] 40 CFR 51.165(a)(1)(xliv) and 40 CFR 52.21(b)(56) define functionally equivalent component, which means a component that serves the same purpose as the replaced component. The definitions of functionally equivalent component and basic design parameters were vacated. However, even though these definitions were removed, they can still be used as guidance to define replacements. See 86 FR 37918 stating: "However, while not controlling, the EPA and stakeholders may continue to look to the vacated definitions from the ERP rule to guide their understanding of the definition of replacement unit."

[6] 40 CFR 51.165(h)(2) and 40 CFR 52.21(cc)(2) define basic design parameters

[7] 40 CFR 51.165(a)(1)(vii)(B) and 40 CFR 52.21(b)(7)(ii)

[8] 40 CFR 51.165(a)(2)(ii)(C) and 40 CFR 52.21(a)(2)(iv)(c)

permitted unit(s). PAR 1304 subparagraph (f)(1)(C) also specifies that an increase in efficiency is not an increase in the physical and operational design capacity.

The BACT exemption is not applicable for facility expansions, modernization projects, upgrades, or improvements that are not for BARCT compliance. This provision is to ensure that the BACT exemption is not used for the facility to increase utilization or capacity, which may result in higher emissions. The BACT exemption is not intended for debottlenecking or shifting loads from existing units to new or modified units with add-on air pollution controls, which would result in both an increase in utilization and actual emissions above current allowable levels. Excluding projects that are not related to an air pollution control project for NOx BARCT compliance, such as those that are solely for facility modernization or expansion, is necessary to ensure that the limited BACT exemption would not be backsliding under SB 288.

Subparagraph (f)(1)(D)

The proposed criteria in PAR 1304 subparagraph (f)(1)(D) requires that the emissions from new or modified permit unit~~(s)~~ do not cause an exceedance of any state or national ambient air quality standard. This provision is a safeguard to ensure that an emission increase associated with the new or modified permit unit~~(s)~~ will not result in a potential exceedance of any ambient air quality standard, as demonstrated with modeling as required in Rule 1303~~1 – General~~ paragraph (b)(1). Rule 1303 paragraph (b)(1) requires that an applicant substantiate with modeling that a source will not cause a violation, or make significantly worse an existing violation, of any state or national ambient air quality standard at any receptor location within the South Coast Air Quality Management District. Modeling for Rule 1303 paragraph (b)(1) is conducted according to Appendix A of Rule 1303, or other analysis approved by the Executive Officer or designee. Appendix A specifies that an applicant must show that a significant increase in air quality concentration will not occur at any receptor location by either providing an approved modeling analysis or using the Screening Analysis. The Screening Analysis compares the emissions from the source an applicant is applying for to the Allowable Emissions in ~~Par~~ PAR 1304 Table A-1. If the emissions are less than the Allowable Emissions, then no further analysis is required. If the emissions are greater than the allowable emissions, a more detailed air quality modeling analysis is required. Furthermore, the modeling demonstration is not required for VOC or SOx.

Subparagraph (f)(1)(E)

PAR 1304 subparagraph (f)(1)(E) specifies that the BACT exemption can only apply to new or modified permit units that are not part of a project that is subject to federal major NSR. New or modified permit units that constitute a federal Major Stationary Source or Major Modification will be subject to BACT. Federal NSR applicability will be determined according to the federal definitions for Major Stationary Source or Major Modification as defined in 40 CFR 51.165 and 40 CFR 52.21. The provisions for the federal NSR program codified in 40 CFR 51.165 are applicable to the nonattainment pollutants, while 40 CFR 52.21 are the federal Prevention of Significant Deterioration (PSD) provision for attainment/unclassifiable pollutants.

PAR 1304 includes a provision in subparagraph (f)(1)(E) to clarify that it is permissible to use a mass balance engineering calculation to calculate the increase in emissions of PM when installing add-or air pollution control equipment with ammonia. A mass balance calculation may be used provided it employs the percent conversion of SO2 to SO3 found in the catalyst manufacturer specifications and uses the representative fuel gas sulfur content. U.S. EPA confirmed that this approach is acceptable for the purpose of NSR applicability.

Paragraph (f)(2)

The purpose of PAR 1304 paragraph (f)(2) is to clarify that new or modified permit units that qualify for the BACT exemption specified in PAR 1304 paragraph (f)(1) are still subject to all other requirements of Regulation XIII, including but not limited to, permit conditions limiting monthly maximum emissions as required in Rule 1313 – Permits to Operate. Specifically, permits issued utilizing the narrow BACT exemption are still required to have permit conditions limiting monthly maximum emissions pursuant to Rule 1313 paragraph (g)(2).

Summary of Proposed Recission of 1109

Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries, applies to boilers and process heaters in petroleum refineries, and established a refinery-wide NOx emission limit of 0.14 pound per million British thermal units (lb/MMBTU) (approximately 120 ppmv NOx corrected to three percent oxygen) for boilers and process heaters operated on gaseous fuel, 0.308 lb/MMBTU (approximately 250 ppmv NOx corrected to three percent oxygen) for units operated on liquid fuel, and a weighted average of these limits for units operated concurrently on both liquid and gaseous fuels. Boilers and process heaters with maximum rated capacities equal to or less than 40 MMBTU/hr were also exempt from section (b) requirements of the rule. Rule 1109 section (e) set a compliance schedule for the boilers and process heaters, but ultimately, facilities demonstrated compliance with Regulation XX – RECLAIM instead. Because PR 1109.1 applies to a greater range of facilities: petroleum refineries and facilities with operations related to petroleum refineries; and applies to a greater range of equipment also including FCCUs, SRU/TGs, coke calciners, gas turbines, etc., the regulatory aim and components of Rule 1109 are being folded into and made more stringent in PR 1109.1.

2.5 SUMMARY OF AFFECTED EQUIPMENT

While PR 429.1, and PARs 1304 and 2005 are part of the proposed project, no physical changes are required with implementation of those rules. The following combustion equipment categories that will be applicable to PR 1109.1 are: 1) boilers; 2) flares; 4) fluidized catalytic cracking units; 4) gas turbines; 5) petroleum coke calciners; 6) process heaters; 7) SMR heaters; 8) SMR heaters with gas turbine; 9) sulfur recover units/tail gas treating units; 10) sulfuric acid furnaces; and 11) vapor incinerators. PR 1109.1 will transition affected equipment operating at 16 facilities, including nine petroleum refineries, three small refineries, and four facilities with related operations, that are subject to transition from the NOx RECLAIM program to a command-and-control regulatory structure. A list of affected facilities and equipment is provided in Appendix D of this Final ~~Draft~~ SEA.

Table 2.5-1 provides a summary of the combustion equipment types and the total number of equipment that will be subject to PR 1109.1.

Table 2.5-1: Affected Equipment Subject to PR 1109.1

Equipment Type	Total Number
Heaters/Boilers	228
Sulfur Recovery Units/Tail Gas Treating Units (1)	16
Vapor Incinerators	13
Gas Turbines (2)	12
Start-Up Heaters/Boilers	8
FCCU	5
Coke Calciner (3)	1
Flare	1
Total	**284**

(1) 3 units have in-line heaters
(2) 10 gas turbines with duct burners, 3 without
(3) Coke calciner includes a pyroscrubber and kiln

Of these 284 pieces of equipment, staff estimates 74 units will be retrofit with new SCRs, 16 SCRs could be upgraded, and 76 units expected to be retrofitted with ULNB. In lieu of SCR, two pieces of equipment may be retrofit with a LoTOx^{TM} wet gas scrubber or Ultracat dry gas scrubber. In addition, staff estimates 52 boilers and process heaters will be retrofit with emerging LNB technology at time of burner replacement at a future date. Instead of retrofitting existing units with emission controls to comply with PR 1109.1, some facilities may replace existing units with new units (also with new emissions controls) that serve the same purpose. As part of any potential compliance project, facilities may need to replace and/or upgrade existing process equipment and/or utilities including potentially installing fuel gas sulfur treatment (if required).

2.6 TECHNOLOGY OVERVIEW

2.6.1 Combustion Equipment

Combustion is a high temperature chemical reaction resulting from burning a gas, liquid, or solid fuel (e.g., natural gas, diesel, fuel oil, gasoline, propane, and coal) in the presence of air (oxygen and nitrogen) to produce: 1) heat energy and, 2) water vapor or steam. In an ideal combustion reaction, the entire amount of fuel needed is completely combusted in the presence of air so that only carbon dioxide (CO_2) and water are produced as by-products. However, because fuel contains other components such as nitrogen and sulfur, and because the amount of air mixed with the fuel can vary, in practice, the combustion of fuel is not a "perfect" reaction. As such, uncombusted fuel and smog-forming by-products such as NOx, SOx, carbon monoxide (CO), and soot (solid carbon) can be discharged into the atmosphere.

There are three types of NOx formed during combustion: 1) thermal NOx, 2) fuel NOx, and 3) prompt NOx. Thermal NOx is produced from the reaction between the nitrogen and oxygen in the combustion air at high temperatures. Fuel NOx is formed from the reaction between the nitrogen already present in the fuel and the available oxygen in the combustion air. Prompt NOx is formed from nitrogen in the air combining with fuel in fuel-rich conditions. (Some writers and analysts discount prompt NOx because they assume that fuel intrinsically contains very large or very small amounts of nitrogen, or are considering burners that are intended to have or not have fuel-rich regions in the flame. This discussion will primarily focus on thermal NOx and fuel NOx.)[9] As the source of nitrogen in fuel is more prevalent in oil and coal, but is negligible in natural gas, the amount of fuel NOx generated is dependent on fuel type. For example, with oil that contains significant amounts of fuel-bound nitrogen, fuel NOx can account for up to 50 percent of the total NOx emissions generated. In another example, only 10 percent of NOx emissions from FCCUs are thermal NOx while the remaining 90 percent of NOx is generated from fuel by combusting petroleum coke. Though boilers, process heaters, petroleum coke calciners, FCCUs, gas turbines, and other miscellaneous equipment have varying purposes in commercial, industrial, and utility applications, at a minimum, they all generate thermal NOx as a combustion by-product. The following provides a brief description of the various types of existing combustion equipment that may be affected by the proposed project and subsequently retrofitted with NOx control equipment.

Process Heaters and Boilers

Process heaters and boilers are used extensively throughout various processes in refinery operations such as distillation, hydrotreating, fluid catalytic cracking, alkylation, reforming, and delayed coking.

A process heater is a type of combustion equipment that burns liquid, gaseous, or solid fossil fuel for the purpose of transferring heat from combustion gases to heat water or process streams. Process heaters are not and do not include kilns or ovens used for drying, curing, baking, cooking, calcining, or vitrifying; or any unfired waste heat recovery heater that is used to recover sensible heat from the exhaust of any combustion equipment.

A boiler, also referred to as a steam generator, is a steel or cast-iron pressure vessel equipped with burners that combust liquid, gas, or solid fossil fuel to produce steam or hot water. Boilers are classified according to the amount of energy output in millions of British Thermal Units per hour (mmBTU/hr), the type of fuel burned (natural gas, diesel, fuel oil, etc.), operating steam pressure in pounds per square inch (psi), and heat transfer media. In addition, boilers are further defined by the type of burners used and air pollution control techniques. The burner is where the fuel and combustion air are introduced, mixed, and then combusted.

Refinery process heaters and boilers are primarily fueled by refinery gas, one of several products generated at the refinery. In addition, most of the refinery process heaters and boilers are designed to also operate on natural gas, but liquid or solid fuels are rarely used. The combustion of fuel generates NOx, primarily "thermal" NOx with small contribution from "fuel" NOx and "prompt" NOx.

Process heaters and boilers have various designs, applications, and specialized uses, which allow for further classification. Steam methane reformer (SMR) heaters and sulfuric acid furnaces are designed to serve different purposes and combust different fuel types. The fuel burned may be refinery gas, natural gas, pressure swing adsorption (PSA) off gas, sulfur, and/or hydrogen sulfide. SMR heaters generate heat for the endothermic reforming reaction of hydrocarbon and steam over a nickel-based catalyst in hydrogen production. They typically operate at a higher temperature than traditional process heaters (2,100 ^{o}F) and therefore, have the potential for higher NOx generation. Sulfuric acid furnaces are utilized at sulfuric acid plants to produce sulfur dioxide gas which ultimately is converted into sulfuric acid. There are two sulfuric acid furnaces subject to PR 1109.1 which are spent acid regeneration furnaces, primarily used for the decomposition of spent sulfuric

9 U.S. Environmental Protection Agency. 1999. Technical Bulletin: Nitrogen Oxides (NOx) Why and How they are Controlled. Accessed August 1, 2021. https://www3.epa.gov/ttn/catc/dir1/fnoxdoc.pdf

acid generated from the refinery's alkylation process. Feedstock from a variety of sulfur-containing streams are fed into the furnace's combustion chamber. Depending on facility location, feedstock includes spent acid, hydrogen sulfide, sulfur, and/or hydrocarbon at various ratios. Hydrogen sulfide and sulfur both provide heating value when used as feedstock, so overall fuel demand will be less when they are present at higher ratios, which can ultimately affect the overall NOx emission.

For the purpose of the analysis in this SEA, controlling NOx emissions from refinery boilers and process heaters is assumed to be accomplished with selective catalytic reduction (SCR) technology, and/or replacing existing burners with Ultra low-NOx burners. For a full description of these control technologies, see the NOx Control Technologies section.

Gas Turbines

Gas turbines are used in refineries to produce both electricity and steam. Refinery gas turbines are typically combined cycle units that use two work cycles from the same shaft operation. Refinery gas turbines also have an additional element of heat recovery from its exhaust gases to produce more power by way of a steam generator. Gas turbines can operate on both gaseous and liquid fuels. Gaseous fuels include natural gas, process gas, and refinery gas. Liquid fuels typically include diesel. The units in this category are cogenerating units that recover the useful energy from heat recovery for producing process steam.

Frame gas turbines are exclusively used for power generation and continuous base load operation ranging up to 250 MW with simple-cycle efficiencies of approximately 40 percent and combined-cycle efficiencies of 60 percent. The existing gas turbines operating at the refineries are rated from seven MW to 83 MW. Most of the refinery gas turbines are operated with duct burners, heat recovery steam generator (HRSG), SCR, and CO catalysts. Figure 2.6-1 shows a typical layout of a combined cycle utility gas turbine with a duct burner, HRSG, and control system.

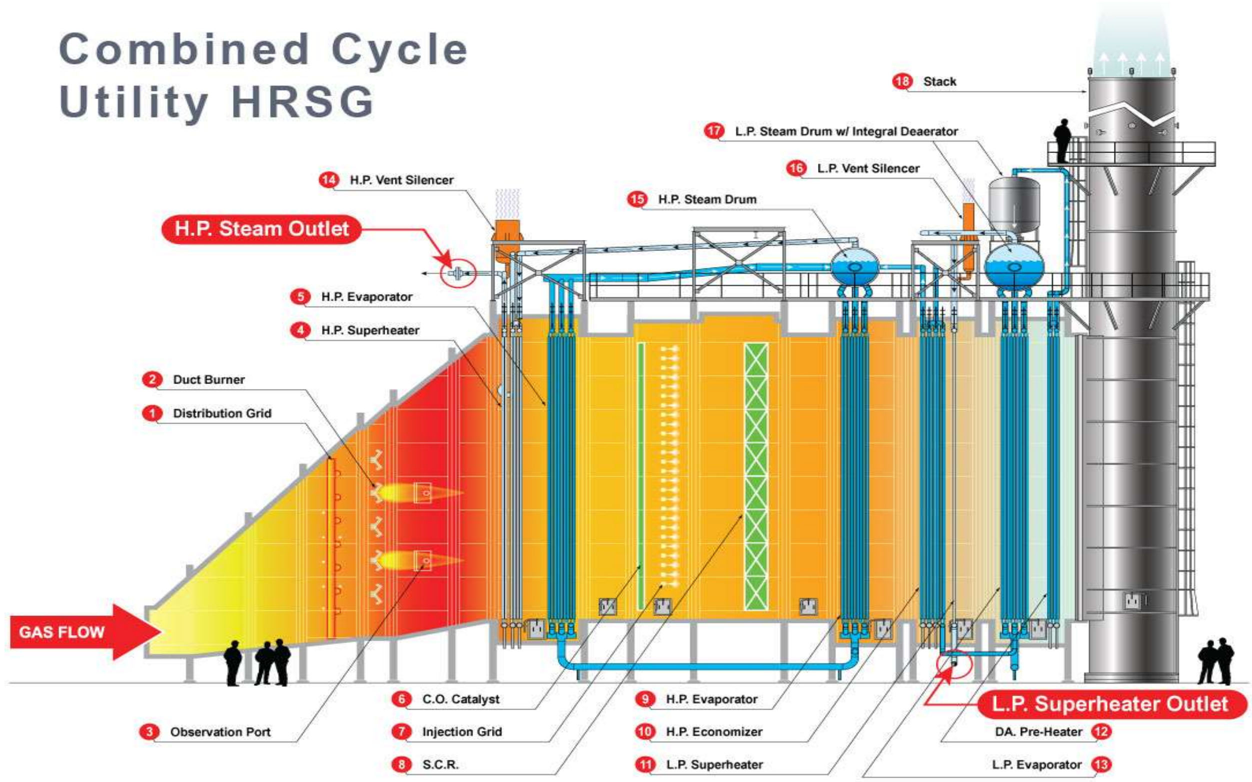


Figure 2.6-1: Gas Turbine with Duct Burner

For the purpose of the analysis in this SEA, controlling NOx emissions from refinery gas turbines is assumed to be accomplished with upgrading existing SCR technology. For a full description of this control technology, see the NOx Control Technologies section.

Sulfur Recovery Units and Tail Gas Units (SRU/TGUs)

Refinery SRU/TGUs, including their incinerators, are classified as major sources of both NOx and SOx emissions. Because sulfur is a naturally occurring and undesirable component of crude oil, refineries employ a sulfur recovery system to maximize sulfur removal. A typical sulfur removal or recovery system will include a sulfur recovery unit (e.g., Claus unit) followed by a tail gas treatment unit (e.g., amine treating) for maximum removal of hydrogen sulfide (H_2S). A Claus unit consists of a reactor, catalytic converters and condensers. Two chemical reactions occur in a Claus unit. The first reaction occurs in the reactor, where a portion of H_2S reacts with air to form sulfur dioxide (SO_2) followed by a second reaction in the catalytic converters where SO_2 reacts with H_2S to form liquid elemental sulfur. Side reactions producing carbonyl sulfide (COS) and carbon disulfide (CS_2) can also occur. These side reactions are problematic for Claus plant operators because COS and CS_2 cannot be easily converted to elemental sulfur and carbon dioxide. Liquid sulfur is recovered after the final condenser. The combination of two converters with two condensers in series will generally remove as much as 95 percent of the sulfur from the incoming acid gas. To increase removal efficiency, some newer sulfur recovery units may be designed with three to four sets of converters and condensers.

To recover the remaining sulfur compounds after the final pass through the last condenser, the gas is sent to a tail gas treatment process such as a SCOT or Wellman-Lord treatment process. For example, the SCOT tail gas treatment is a process where the tail gas is sent to a catalytic reactor and the sulfur compounds in the tail gas are converted to H_2S. The H_2S is absorbed by a solution of amine or diethanol amine (DEA) in the H_2S absorber, steam-stripped from the absorbent solution in the H_2S stripper, concentrated, and recycled to the front end of the sulfur recovery unit. This approach typically increases the overall sulfur recovery efficiency of the Claus unit to 99.8 percent or higher. However, the fresh acid gas feed rate to the sulfur recovery unit is reduced by the amount of recycled stream, which reduces the capacity of the sulfur recovery unit. The residual H_2S in the treated gas from the absorber is typically vented to a thermal oxidizer where it is oxidized to sulfur dioxide (SO_2) before venting to the atmosphere.

The Wellman-Lord tail gas treatment process is when the sulfur compounds in the tail gas are first incinerated to oxidize to SO_2. After the incinerator, the tail gas enters a SO_2 absorber, where the SO_2 is absorbed in a sodium sulfite (Na_2SO_3) solution to form sodium bisulfite ($NaHSO_3$) and sodium pyrosulfate ($Na_2S_2O_5$). The absorbent rich in SO_2 is then stripped, and the SO_2 is recycled back to the beginning of the Claus unit. The residual sulfur compounds in the treated tail gas from the SO_2 absorber is then vented to a thermal (or catalytic) oxidizer (incinerator) where the residual H_2S in the tail gas is oxidized to SO_2 before venting to the atmosphere. NOx is a by-product of operating the incinerator.

The type of NOx control option to be utilized in response to this portion of the proposed project is assumed to be replacing existing burners with Ultra low-NOx. For a full description of this control technology, see the NOx Control Technologies section.

<u>Petroleum Coke Calciner</u>

Petroleum coke, the heaviest portion of crude oil, cannot be recovered in the normal oil refining process. Instead, it is processed in a delayed coker unit to generate a carbonaceous solid referred to as "green coke," a commodity. To improve the quality of the product, if the green coke has a low metals content, it will be sent to a calciner to make calcined petroleum coke. Calcined petroleum coke can be used to make anodes for the aluminum, steel, and titanium smelting industry. If the green coke has a high metals content, it is used as fuel grade coke by the fuel, cement, steel, calciner and specialty chemicals industries.

As shown in Figure 2.6-2, the process of making calcined petroleum coke begins when the green coke feed produced by the delayed coker unit is screened and transported to the calciner unit where it is stored in a covered coke storage barn. The screened and dried green coke is introduced into the top end of a rotary kiln and is tumbled by rotation under high temperatures that range between 2,000 and 2,500 degrees Fahrenheit (°F). The rotary kiln relies on gravity to move coke through the kiln countercurrent to a hot stream of combustion air produced by the combustion of natural gas or fuel oil. As the green coke flows to the bottom of the kiln, it rests in the kiln for approximately one additional hour to eliminate any remaining moisture, impurities, and hydrocarbons. Once discharged from the kiln, the calcined coke is dropped into a cooling chamber, where it is quenched with water, treated with de-dusting agents to minimize dust, carried by conveyors to storage tanks. Eventually, the calcined coke is transported by truck to the Port of Long Beach for export, or is loaded onto railcars for shipping to domestic customers. As the green coke is processed under high heat conditions in the rotary kiln, NOx emissions are generated. NOx is also generated from combusting fuel oil to generate high heating values in the rotary kiln.

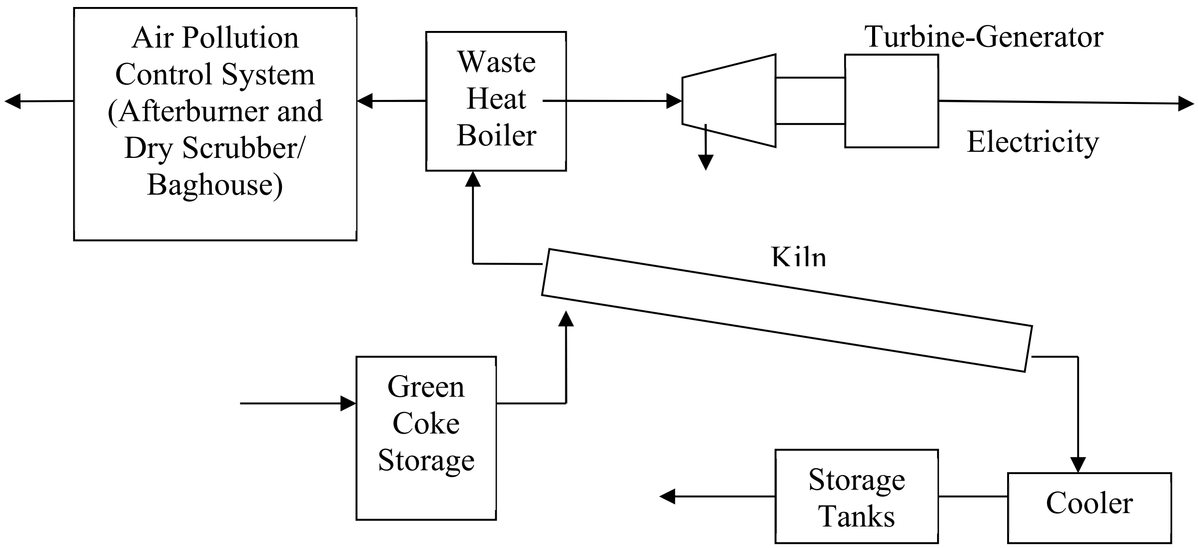


Figure 2.6-2: Coke Calciner Process

There are three multi-pollutant control technologies for the low temperature removal of NOx emissions from the coke calciner: 1) LoTOx™ with wet gas scrubber, 2) UltraCat™ dry gas scrubber, or 3) SCR technology. For a full description of these control technologies, see the NOx Control Technologies section.

Fluidized Catalytic Cracking Units (FCCUs)

The purpose of an FCCU at a refinery is to convert or "crack" heavy oils (hydrocarbons), with the assistance of a catalyst, into gasoline and lighter petroleum products. Each FCCU consists of three main components: a reaction chamber, a catalyst regenerator and a fractionator.

As shown in Figure 2.6-3, the cracking process begins in the reaction chamber where fresh catalyst is mixed with pre-heated heavy oils (crude) known as the fresh feed. The catalyst typically used for cracking is a fine powder made up of tiny particles with surfaces covered by several microscopic pores. A high heat-generating chemical reaction occurs that converts the heavy oil liquid into a cracked hydrocarbon vapor mixed with catalyst. As the cracking reaction progresses, the cracked hydrocarbon vapor is routed to a distillation column or fractionator for further separation into lighter hydrocarbon components than crude such as light gases, gasoline, light gas oil, and cycle oil.

Towards the end of the reaction, the catalyst surface becomes inactive or spent because the pores are gradually coated with a combination of heavy oil liquid residue and solid carbon (coke), thereby reducing its efficiency or ability to react with fresh heavy liquid oil in the feed. To prepare the spent catalyst for re-use, the remaining oil residue is removed by steam stripping. The spent catalyst is later cycled to the second component of the FCCU, the regenerator, where hot air burns the coke layer off of the surface of each catalyst particle to produce reactivated or regenerated catalyst. Subsequently, the regenerated catalyst is cycled back to the reaction chamber and mixed with more fresh heavy liquid oil feed. Thus, as the heavy oils enter the cracking process through the reaction chamber and exit the fractionator as lighter components, the catalyst continuously circulates between the reaction chamber and the regenerator.

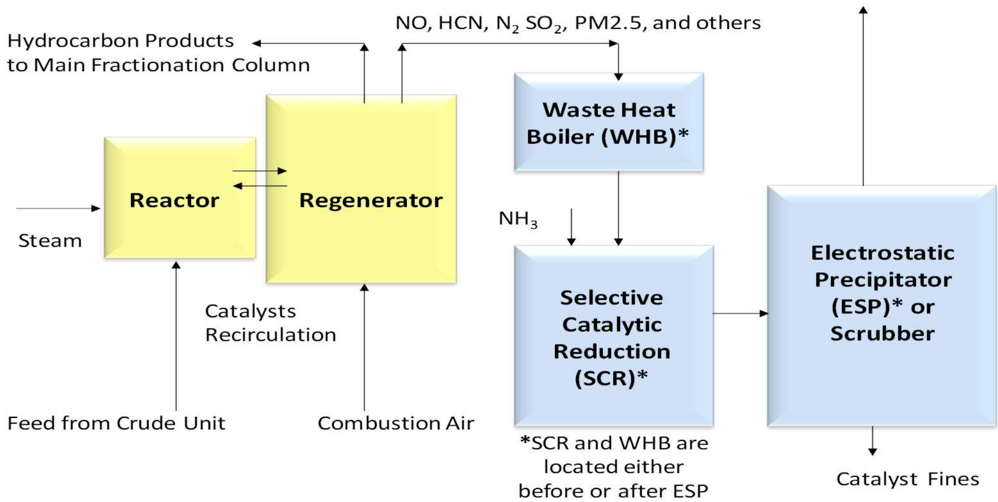


Figure 2.6-3: Simplified Schematic of FCCU Process

During the regeneration cycle, large quantities of catalyst are lost in the form of catalyst fines or particulates thus making FCCUs a major source of primary particulate emissions (PM10 and PM2.5) at refineries. In addition, particulate (PM) precursor emissions such as SOx (because crude oil naturally contains sulfur) and NOx, additional secondary particulates (i.e., formed as a result of various chemical reactions), plus carbon monoxide (CO) and carbon dioxide (CO_2) are produced due to coke burn-off during the regenerator process.

Approximately 90 percent of the NOx generated from the FCCUs is from the nitrogen in the feed that is accumulated in the coke (fuel NOx) which is then burned-off in the regenerator. The remaining 10 percent of the NOx generated from the FCCUs is “thermal” NOx which is generated in the high temperature zones in the regenerator, and “prompt” NOx. Combustion in a FCCU regenerator generates various pollutants (e.g., NO, N_2O, NO_2, HCN, NH_3, SO_2, etc.) and their dynamic interaction with each other is complex. “Fuel” nitrogen in the coke is first converted to HCN. HCN is thermodynamically unstable and it is converted to NH_3, N_2, NO, N2O, and NO_2. The rates of these reactions depend heavily on the FCCU regenerator temperatures and configuration.

Currently, refineries may operate FCCUs by utilizing NOx reducing additives to promote the conversion of NOx, HCN, and NH_3 to elemental nitrogen (N_2) and reduce NOx emissions. The removal efficiency for NOx reducing additives can range between 50 percent and 80 percent. A simplified version of the chemical reactions in the FCCU regenerator is shown in Figure 2.6-4.

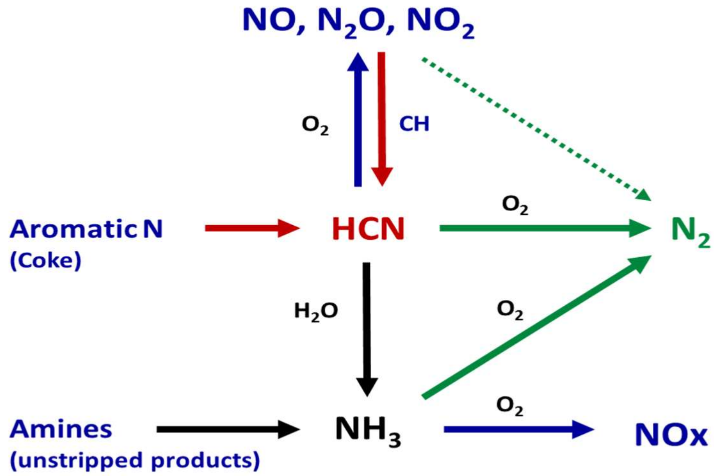


Figure 2.6-4: Nitrogen Chemistry in the FCCU Regenerator

When using NOx reducing additives, manufacturers recommend the following best practices to minimize the formation of NOx and simultaneously promote the conversion of CO to CO_2: 1) minimize excess oxygen since higher amounts of excess oxygen favors the undesirable formation of NOx rather than N_2; 2) reduce nitrogen in the feed stream; and, 3) utilize non-platinum CO promoters.

To further reduce NOx emissions from a FCCU (beyond what is currently being achieved through the use of NOx reducing additives, new SCR technology or LoTOx™ with wet gas scrubber would need to be implemented. For a full description of this control technology, see the NOx Control Technologies section.

Vapor Incinerators

Incinerators control VOCs emissions released form industrial sources by means of thermal destruction. The term “incineration” refers to an ultimate disposal method by thermal treatment of waste materials (solid, liquid, or gas) through a combustion process in the presence of oxygen. The combustion process increases the temperature of the material to higher than its auto-ignition point, and maintains the high temperature for sufficient time to complete the combustion of fuel to carbon dioxide and water. The incineration of nitrogen-bound wastes at high temperatures in a thermal oxidizer generates high levels of nitrogen oxide emissions. Moreover, often auxiliary fuel (e.g., natural gas) must be added to the waste gas stream to help with raising its temperature to the desired levels if the combustion of VOCs in the stream is insufficient.

The type of NOx control option to be utilized in response to this portion of the proposed project is assumed to be replacing existing burners with Ultra low-NOx. For a full description of this control technology, see the NOx Control Technologies section.

2.6.2 NOx Control Technologies

Ultra Low-NOx Burners (ULNB)

For gaseous fuels, thermal NOx is generally the largest contributor of NOx emissions. High flame temperatures trigger the disassociation of nitrogen molecules from combustion air and a chain reaction with oxygen follows to form oxides of nitrogen. Factors that minimize the formation of thermal NOx include reduced flame temperature, shortened residence time, and an increased fuel to air ratio. To reduce NOx emissions, combustion parameters can be optimized, control techniques can be applied downstream of the combustion zone, or a combination of the two approaches can be utilized. Common types of combustion modification include: lowered flame temperature; reduced residence time at high combustion temperature; and reduced oxygen concentration in the high temperature zone.

There are a variety of configurations and types of burners for ultra-low NOx burner (ULNB) systems. Often, fuel and air are pre-mixed prior to combustion. This results in a lower and more uniform flame temperature. Some premix burners also use staged combustion with a fuel rich zone to start combustion and stabilize the flame and a fuel lean zone to complete combustion and reduce the peak flame temperature. These burners can also be designed to spread flames over a larger area to reduce hot spots and lower NOx emissions. Radiant premix burners with ceramic, sintered metal or metal fiber heads spread the flame and produce more radiant heat. When a burner produces more radiant heat, it results in less heat escaping the boiler through the exhaust gases.

Most premix burners require the aid of a blower to mix the fuel with air before combustion takes place (primary air). A commonly used application in combination with these burners is flue gas recirculation (FGR). FGR recycles a portion of the exhaust stream back into the burner. Increasing the amount of primary air and/or use of FGR can reduce flame temperature but it also reduces the temperature of combustion gases through dilution and can reduce efficiency. To maintain efficiency a manufacturer may have to add surface area to the heat exchanger. Increasing the primary air may also destabilize the flame. Ultra-low NOx burners require sophisticated controls to maintain emissions levels and efficiency, to stabilize the flame, and to maintain a turndown ratio that is sufficient for the demands of the particular operation.

<u>Selective Catalytic Reduction (SCR)</u>

Selective Catalytic Reduction (SCR) is post-combustion control equipment that is considered to be BARCT, if cost-effective and feasible, for NOx control of existing combustion sources such as boilers, process heaters, and FCCUs as it is capable of reducing NOx emissions by as much as 95 percent or higher. A typical SCR system design consists of an ammonia storage tank, ammonia vaporization and injection equipment, a booster fan for the flue gas exhaust, an SCR reactor with catalyst, an exhaust stack plus ancillary electronic instrumentation and operations control equipment. The way an SCR system reduces NOx is by a matrix of nozzles injecting a mixture of ammonia and air directly into the flue gas exhaust stream from the combustion equipment. As this mixture flows into the SCR reactor that is replete with catalyst, the catalyst, ammonia, and oxygen (from the air) in the flue gas exhaust reacts primarily (i.e., selectively) with NO and NO_2 to form nitrogen and water in the presence of a catalyst. The amount of ammonia introduced into the SCR system is approximately a one-to-one molar ratio of ammonia to NOx for optimum control efficiency, though the ratio may vary based on equipment-specific NOx reduction requirements. There are two main types of catalysts: one in which the catalyst is coated onto a metal structure and a ceramic-based catalyst onto which the catalyst components are calcified. Commercial catalysts used in SCRs are available in two types of solid, block configurations or modules, plate or honeycomb type, and are comprised of a base material of titanium dioxide (TiO_2) that is coated with either tungsten trioxide (WO_3), molybdic anhydride (MoO_3), vanadium pentoxide (V_2O_5), iron oxide (Fe_2O_3), or zeolite catalysts. These catalysts are used for SCRs because of their high activity, insensitivity to sulfur in the exhaust, and useful life span of approximately five years or more. Ultimately, the material composition of the catalyst is dependent upon the application and flue gas conditions such as gas composition, temperature, et cetera.

For conventional SCRs, the minimum temperature for NOx reduction is 500 ^{o}F and the maximum operating temperature for the catalyst is 800 ^{o}F. Depending on the application, the type of fuel combusted, and the presence of sulfur compounds in the exhaust gas, the optimum flue gas temperature of an SCR system is case-by-case and will range between 550 ^{o}F and 750 ^{o}F to limit the occurrence of several undesirable side reactions at certain conditions. One of the major concerns with the SCR process is the poisoning of the catalyst due to the presence of sulfur and the oxidation of sulfur dioxide (SO_2) in the exhaust gas to sulfur trioxide (SO_3) and the subsequent reaction between SO_3 and ammonia to form ammonium bisulfate or ammonium sulfate. The formation of either ammonium bisulfate or ammonium sulfate depends on the amount of SO_3 and ammonia present in the flue gas and can cause equipment plugging downstream of the catalyst. The presence of particulates, heavy metals and silica in the flue gas exhaust can also limit catalyst performance. However, minimizing the quantity of injected ammonia and maintaining the ammonia temperature within a predetermined range will help avoid these undesirable reactions while minimizing the production of unreacted ammonia which is commonly referred to as 'ammonia slip.' Depending on the type of combustion equipment utilizing SCR technology, the typical amount of ammonia slip can vary between less than five ppmv when the catalyst is fresh and 20 ppmv at the end of the catalyst life.

In addition to the conventional SCR catalysts, there are high temperature SCR catalysts that can withstand temperatures up to 1200 ^{o}F and low temperature SCR catalysts that can operate below 500 ^{o}F.

Further, SCR manufacturers have developed Ammonia Slip Catalyst (ASC) which is a layer of catalyst that is installed downstream of the SCR catalyst to enhance the selective reduction of NO to N2 and supporting the oxidation of CO to CO2 while suppressing the oxidation of NH3 to NOx. Early generation of ASCs were based on precious metal which is highly active for NH_3 oxidation. The use of ASCs allow for operations at higher NH_3/NOx ratios to ensure complete NOx conversion while maintaining low ammonia slip.

Similar to ASC, CO catalyst is used in conjunction with the SCR catalyst to concurrently reduce NOx to N2 and oxidize CO and hydrocarbon to CO2 and water. CO catalyst is typically made of platinum, palladium or rhodium, and is capable of removing approximately 90 percent of CO and 85 percent to 90 percent of hydrocarbon or hazardous air pollutants from an exhaust stream.

Wet Gas Scrubbers (WGSs)

WGS technology is a multi-pollutant control system that primarily controls SOx and PM emissions but can be installed to function with NOx control equipment. WGSs can be used to control emissions from FCCUs, refinery process heaters and boilers, SRU/TGUs, petroleum coke calciners, and cement kilns. There are two types of wet gas scrubbers: 1) caustic-based non-regenerative WGS; and, 2) regenerative WGS.

In non-regenerative wet gas scrubbing, caustic soda (sodium hydroxide - NaOH) or other alkaline reagents, such as soda ash, are used as an alkaline absorbing reagent (absorbent) to capture SO_2 emissions. The absorbent captures SO_2 and sulfuric acid mist (H_2SO4) and converts it to various types of sulfites and sulfates (e.g., $NaHSO_3$, Na_2SO_3, and Na_2SO_4). The absorbed sulfites and sulfates are later separated by a purge treatment system and the treated water, free of suspended solids, is either discharged or recycled.

One example of the caustic-based non-regenerative scrubbing system is the proprietary Electro Dynamic Venturi (EDV) scrubbing system offered by BELCO Technologies Corporation (see Figure 2-7). An EDV scrubbing system consists of three main modules: 1) a spray tower module; 2) a filtering module; and, 3) a droplet separator module. The flue gas enters the spray tower module, which is an open tower with multiple layers of spray nozzles. The nozzles supply a high density stream of caustic/water solution that is directed in a countercurrent flow to the gas flow and encircles, encompasses, wets, and saturates the flue gas. Multiple stages of liquid/gas absorption occur in the spray tower module and SO_2 and acid mist are captured and converted to sulfites and sulfates. Large particles in the flue gas are also removed by impaction with the water droplets.

The flue gas saturated with heavy water droplets continues to move up the wet scrubber to the filtering module where the flue gas reaches super-saturation. At this point, water continues to condense and the fine particles in the gas stream begin to cluster together, to form larger and heavier groups of particles. Next, the flue gas, super-saturated with heavy water droplets, enters the droplet separator module causing the water droplets to impinge on the walls of parallel spin vanes and drain to the bottom of the scrubber.

The spent caustic/water solution purged from the WGS is later processed in a purge treatment unit. The purge treatment unit contains a clarifier that removes suspended solids for disposal. The effluent from the clarifier is oxidized with agitated air to help convert sulfites to sulfates and also reduce the chemical oxygen demand (COD) so that the effluent can be safely discharged to a wastewater system.

A regenerative WGS removes SO_2 from the flue gas by using a buffer solution that can be regenerated. The buffer is then sent to a regenerative plant where the SO_2 is extracted as concentrated SO_2. The concentrated SO_2 is then sent to a sulfur recovery unit (SRU) to recover the liquid SO_2, sulfuric acid and elemental sulfur as a by-product. When the inlet SO_2 concentrations are high, a substantial amount of sulfur-based by-products can be recovered and later sold as a commodity for use in the fertilizer, chemical, pulp and paper industries. For this reason, the use of a regenerative WGS is favored over a non-regenerative WGS.

One example of a regenerative scrubber is the proprietary LABSORB offered by BELCO Technologies Corporation [10, 11]. The LABSORB scrubbing process uses a patented non-organic aqueous solution of sodium phosphate salts as a buffer. This buffer is made from two common available products, caustic and phosphoric acid. The LABSORB system consists of: 1) a quench pre-scrubber; 2) an absorber; and, 3) a regeneration section which typically includes a stripper and a heat exchanger.

In the scrubbing side of the regenerative scrubbing system, the quench pre-scrubber is used to wash out any large particles that are carried over, plus any acid components in the flue gas such as hydrofluoric acid (HF), hydrochloric acid (HCl), and SO_3. The absorption of SO_2 is carried out in the absorber. The absorber typically consists of one single, high-efficiency packed bed scrubber filled with high-efficiency structural packing material. However, if the inlet SO_2 concentration is

[10] *Evaluating Wet Scrubbers*, Edwin H. Weaver of BELCO Technologies Corporation, Petroleum Technology Quarterly, Quarter 3, 2006.

[11] *A Logical and Cost Effective Approach for Reducing Refinery FCCU Emissions.* S.T. Eagleson, G. Billemeyer, N. Confuorto, and E. H. Weaver of BELCO, and S. Singhania and N. Singhania of Singhania Technical Services Pvt., India, Presented at PETROTECH 6th International Petroleum Conference in India, January 2005.

low, a multiple-staged packed bed scrubber, or a spray-and-plate tower scrubber, may be used instead to achieve an ultra-low outlet SO_2 concentration.

The third step in the regenerative wet gas scrubbing system is the regenerative section in which the SO_2-rich buffer stream is steam heated to evaporate the water from the buffer. The buffer stream is then sent to a stripper/condenser unit to separate the SO_2 from the buffer. The buffer free of SO_2 is returned to the buffer mixing tank while the condensed- SO_2 gas stream is sent back to the SRU for further treatment.

LoTOx™ Application with Wet Gas Scrubber

The LoTOx™ is a registered trademark of Linde LLC (previously BOC Gases) and was later licensed to BELCO of Dupont for refinery applications. LoTOx™ stands for "Low Temperature Oxidation" process in which ozone (O_3) is used to oxidize insoluble NOx compounds into soluble NOx compounds which can then be removed by absorption in a caustic, lime or limestone solution. The LoTOx™ process is a low temperature application, optimally operating at about 325 °F.

A typical combustion process produces about 95 percent NO and five percent NO_2. Because both NO and NO_2 are relatively insoluble in an aqueous solution, a WGS alone is not efficient in removing these insoluble compounds from the flue gas stream. However, with a LoTOx™ system and the introduction of O_3, NO and NO_2 can be easily oxidized into a highly soluble compound N_2O_5 (see Reactions 5 and 6) and subsequently converted to nitric acid (HNO_3) (see Reaction 7). Then, in a wet gas scrubber for example, the HNO_3 is rapidly absorbed in caustic (NaOH) (see Reaction 8), limestone or lime solution (see Reactions 9 and 10). In addition, because the rates of oxidizing reactions for NOx (see Reactions 5 and 6) are fast compared to the very slow SO_2 oxidation reaction (see Reaction 11), no ammonium bisulfate ($(NH_4)HSO_4$) or sulfur trioxide (SO_3) is formed.

$NO + O_3 \rightarrow NO_2 + O_2$	(Reaction 5 - Fast)
$2\ NO_2 + O_3 \rightarrow N_2O_5 + O_2$	(Reaction 6 – Fast)
$N_2O_5 + H_2O \rightarrow 2\ HNO_3$	(Reaction 7)
$HNO_3 + NaOH \rightarrow NaNO_3 + H_2O$	(Reaction 8)
$2HNO3 + CaCO3 \rightarrow Ca(NO_3)_2 + H_2O + CO_2$	(Reaction 9)
$2HNO3 + Ca(OH) \rightarrow Ca(NO_3)_2 + 2H_2O$	(Reaction 10)
$SO_2 + O_3 \rightarrow SO_3 + O_2$	(Reaction 11 - Very slow)

The LoTOx™ process requires a source of oxygen and generates O_3 on site. Typically oxygen (O_2) is stored as a liquid in vacuum-jacketed vessels or is delivered by pipeline. O_3 is an unstable gas and it is typically generated on demand from the O_2 supply using an O_3 generator. An O_3 generator is shaped similar to a shell and tube heat exchanger and uses a corona discharge to dissociate the O_2 molecules into individual atoms so that the individual oxygen atoms combine with each other to form O_3. The LoTOx™ process contains an ozone injection manifold designed to achieve uniform distribution and complete mixing. A ratio of 1.75 parts NOx to 2.5 parts O_3 is needed in order to achieve a NOx conversion and reduction of 90 percent to 95 percent. Since sulfur dioxide (SO_2) is an ozone scavenger because it readily bonds with O_3 to form sulfur trioxide (SO_3), the LoTOx™ process typically has a very low O_3 slip (excess O_3) that ranges from zero ppmv to three ppmv. Figure 2.6-5 shows a schematic of the O_3 generation process.

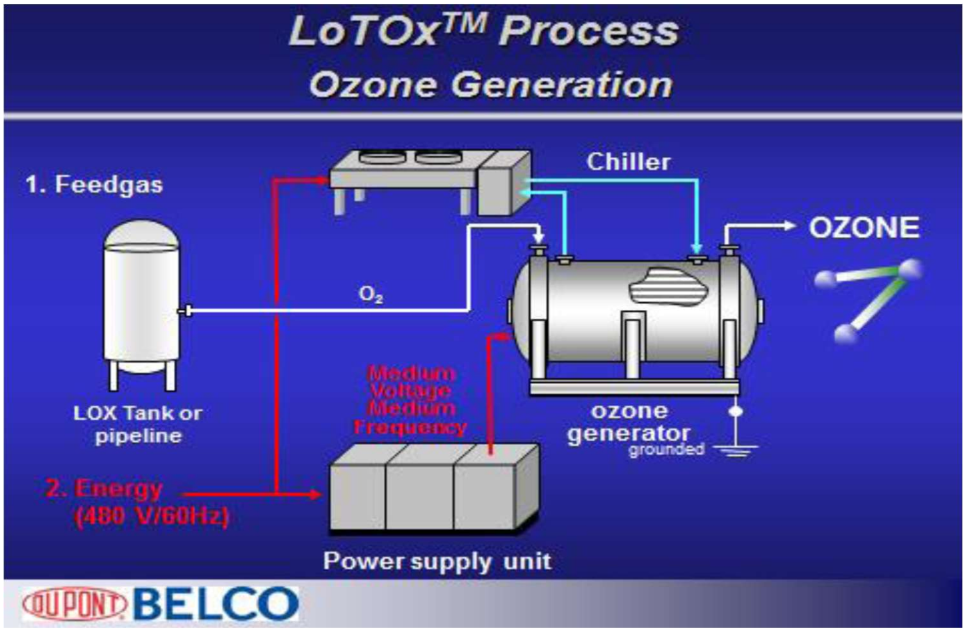


Figure 2.6-5: Ozone Generation Process

The LoTOx™ process can be integrated with any type of wet scrubbers (e.g., venturi, packed beds), semi-dry scrubbers, or wet electrostatic precipitators (ESPs). For example, Linde has engineered more than 24 LoTOx™ applications for EDV™ scrubbers engineered by BELCO since 2007 for refinery FCCU applications. A LoTOx™ system with an EDV™ scrubber is shown in Figure 2.6-6.

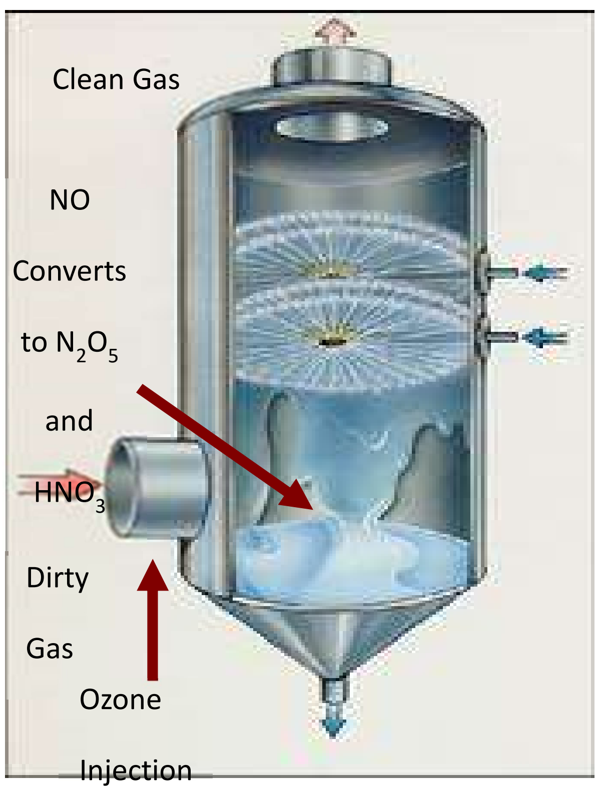


Figure 2.6-6: EDV Scrubber with LoTOx™ Application

In addition, MECS, BELCO's sister company, has engineered more than two dozen DynaWave scrubbers with LoTOx™ systems specifically designed for refinery SRU/TGUs. Figure 2.6-7 shows a schematic for a DynaWave scrubber with a LoTOx™ application.

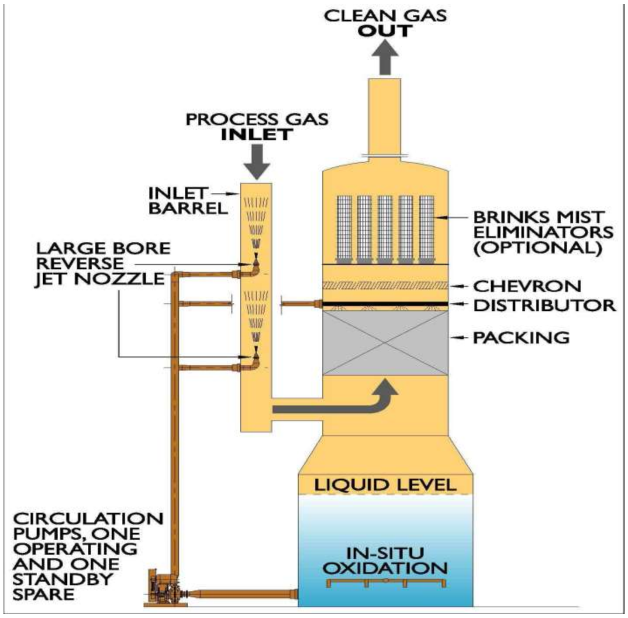


Figure 2.6-7: DynaWave Scrubber with LoTOx™ Application

When compared to SCR technology, the LoTOx™ application has several advantages, as follows:

- Unlike SCR which operates at high temperatures, LoTOx™ is a low temperature operating system that does not require additional heat input to maintain operational efficiency and enable maximum heat recovery of high temperature combustion gases.
- Unlike SCR which is primarily designed to reduce only NOx, LoTOx™ can be integrally connected to a scrubber (e.g., wet or semi-dry scrubber, or wet electrostatic ESP) and become a multi-component air pollution control system capable of reducing NOx, SOx and PM in one system.
- There is no formation of ammonia slip, SO_3, or $(NH_4)HSO_4$ with the LoTOx™ process.

UltraCat™

UltraCat™ is a commercially available multi-pollutant control technology designed to remove NOx and other pollutants such as SO_2, PM, HCl, Dioxins, and HAPs such as mercury in low temperature applications. UltraCat™ technology is comprised of filter tubes which are made of fibrous ceramic materials embedded with proprietary catalysts. The optimal operating temperature range of an UltraCat™ system is approximately 350 °F to 750 °F. In order to achieve a NOx removal efficiency of approximately 95 percent, aqueous ammonia is injected upstream of the UltraCat™ filters. In addition, to remove SO_2, HCl, and other acid gases with a removal efficiency ranging from 90 percent to 98 percent, dry sorbent such as hydrated lime, sodium bicarbonate or trona is also injected upstream of the UltraCat™ filters. UltraCat™ is also capable of controlling particulates to a level of 0.001 grains per standard cubic foot of dry gas (dscf).

The UltraCat™ filters are arranged in a baghouse configuration with a low pressure drop such as five inches water column (inH20) across the system. The UltraCat™ system is equipped with a reverse pulse-jet cleaning action that back flushes the filters with air and inert gas to dislodge the PM deposited on the outside of the filter tubes. Depending on the loading, catalytic filter tubes need to be replaced every five to 10 years. The UltraCat™ system is shown in Figure 2.6-8.

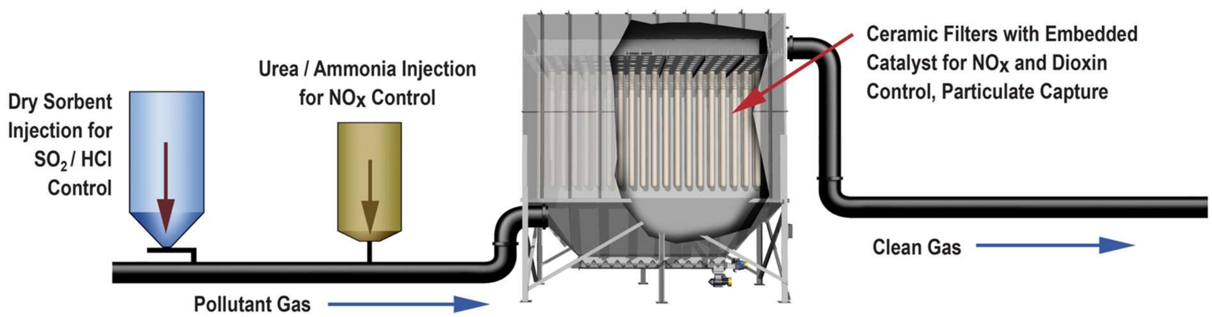


Figure 2.6-8: UltraCat™ System

CHAPTER 3

EXISTING SETTING

Introduction

Existing Setting

Air Quality and Greenhouse Gas Emissions

Hazards and Hazardous Materials

Hydrology (Water Demand)

3.0 INTRODUCTION

To determine the significance of the impacts associated with a proposed project, it is necessary to evaluate the project’s impacts against the backdrop of the environment as it exists at the time the environmental analysis is commenced. CEQA Guidelines Section 15360 defines ˈenvironmentˈ as “the physical conditions that exist within the area which will be affected by a proposed project including land, air, water, minerals, flora, fauna, ambient noise, and objects of historical or aesthetic significance” [*See also* Public Resources Code Section 21060.5]. Furthermore, a CEQA document must include a description of the physical environment in the vicinity of the project, as it exists at the time the environmental analysis is commenced, from both a local and regional perspective [CEQA Guidelines Section 15125]. This environmental setting will normally constitute the baseline physical conditions by which a lead agency determines whether an impact is significant. The description of the environmental setting shall be no longer than is necessary to provide an understanding of the significant effects of the proposed project and its alternatives.

3.1 EXISTING SETTING

The proposed project is comprised of PRs 1109.1 and 429.1, PARs 1304 and 2005, and proposed rescinded Rule 1109. PR 1109.1 has been developed as a command-and-control landing rule for NOx RECLAIM facilities in accordance with the commitment made by Control Measure CMB-05 in the 2016 AQMP. PR 1109.1 has been crafted to reduce NOx emissions from combustion equipment at petroleum refineries and facilities with related operations to petroleum refineries that are currently regulated under the market-based NOx RECLAIM program. PR 429.1, PAR 1304, PAR 2005, and the proposed rescission of Rule 1109 are rule development activities intended to provide support to the implementation of PR 1109.1. If adopted, PR 1109.1 is intended to replace the outdated Rule 1109. PR 429.1 has been developed to address emissions that may occur during the start-up, shutdown or maintenance of a PR 1109.1 combustion unit and/or its associated air pollution control equipment due to the lack of steady-state conditions. PARs 1304 and 2005 were developed to address the NSR issues associated with potential emission increases of PM10 and SOx associated with installation of new or modified SCR technology to comply with the proposed BARCT emission limits in PR 1109.1.

To achieve the BARCT NOx concentration limits under PR 1109.1, installations or modifications of post-combustion air pollution control equipment such as SCRs and replacement of burners with ULNBs are expected to occur. Since PR 429.1, PAR 1304, PAR 2005, and the proposed rescission of Rule 1109 are rule development activities intended to provide support to the implementation of PR 1109.1, and do not require any emission reductions, no physical modifications that would create any secondary adverse environmental impacts are expected to occur for this portion of the proposed project.

The proposed project, PR 1109.1 in combination with supporting rules PR 429.1, PARs 1304 and 2005, and the proposed rescission of Rule 1109, is designed to amend the previous BARCT assessments conducted for: 1) facilities in the refinery sector as previously analyzed in the December 2015 Final PEA for NOx RECLAIM; and 2) Control Measure CMB-05 and the entire RECLAIM Transition project in the 2016 AQMP as previously analyzed in the March 2017 Final Program EIR for the 2016 AQMP. This SEA tiers off of the December 2015 Final PEA for NOx RECLAIM and the March 2017 Final Program EIR for the 2016 AQMP as allowed by CEQA Guidelines Sections 15152, 15162, 15168, and 15385.

The December 2015 Final PEA for NOx RECLAIM analyzed the environmental impacts associated with the physical activities (e.g., installing new or modifying existing air pollution control equipment as summarized in Table 1.1-1) that could occur at nine refinery-sector facilities and 11 non-refinery sector facilities, in lieu of these facilities surrendering NOx RTCs to achieve 14 tpd of NOx emission reductions, in order to implement the NOx BARCT standards. The December 2015 Final PEA for NOx RECLAIM concluded that the following topics would have significant and unavoidable adverse environmental impacts: air quality during construction and GHGs, hazards and hazardous materials associated with ammonia, and hydrology due to water demand during hydrotesting and when operating certain types of air pollution control equipment.

After the amendments to the NOx RECLAIM program were adopted in December 2015, the 2016 AQMP was adopted which identified control measures and strategies to bring the region into attainment with the revoked 1997 8-hour NAAQS (standard) (80 parts per billion (ppb)) for ozone by 2024; the 2008 8-hour ozone standard (75 ppb) by 2032; the 2012 annual PM2.5 standard (12 microgram per cubic meter (ug/m3) by 2025; the 2006 24-hour PM2.5 standard (35 ug/m3) by 2019; and the revoked 1979 1-hour ozone standard (120 ppb) by 2023.

Control Measure CMB-05, one of several components in the 2016 AQMP, was developed to identify a series of approaches that can be explored to ensure equivalency with command-and-control regulations implementing BARCT, and to generate five tons per day of further NOx emission reductions at RECLAIM facilities as soon as feasible, and no later than 2025, and to transition to a command-and-control regulatory structure requiring BARCT level controls as soon as practicable. Because many of the RECLAIM program's original advantages appeared to be diminishing, CMB-05 prescribed an orderly sunset of the RECLAIM program to create more regulatory certainty and to reduce compliance burdens for RECLAIM facilities, while also achieving more actual and SIP creditable emissions reductions.

The existing setting is the physical environmental conditions as they existed at the time the Notice of Preparation (NOP) was published, or if no NOP is published, at the time the environmental analysis is commenced [CEQA Guidelines Section 15125]. The NOP for the Draft PEA for NOx RECLAIM was published on December 5, 2014 while the NOP for the Draft Program EIR for the 2016 AQMP was published on July 5, 2016. The analysis in the December 2015 Final PEA for NOx RECLAIM contains a detailed analysis of the environmental setting and corresponding environmental effects specifically tailored to implementing BARCT for combustion equipment for specific refinery-sector facilities which are the focus of the BARCT assessment in PR 1109.1. However, the March 2017 Final Program EIR for the 2016 AQMP contains a more generalized analysis of the environmental impacts associated with implementing BARCT Control Measure CMB-05 and the entire RECLAIM Transition project, along with a larger suite of other control measures applicable to a wide variety of facilities and their emission sources in the 2016 AQMP.

When comparing the types of activities and associated environmental impacts with implementing the BARCT standards for the equipment and facilities subject to the December 2015 NOx RECLAIM amendments as identified in Table 1.1-1 as previously analyzed in the December 2015 Final PEA for NOx RECLAIM, to the additional equipment and sources that will need to comply with the BARCT requirements in PR 1109.1 as identified in Table 1.1-2, the type and extent of the physical activities that facility operators may undertake to comply with the BARCT requirements in PR 1109.1 are expected to be similar and will cause similar potentially significant secondary adverse environmental impacts for the same environmental topic areas that were identified and analyzed in the December 2015 Final PEA for NOx RECLAIM.

A subset of the NOx RECLAIM universe of refinery-sector facilities that would be affected by the proposed project (e.g., nine facilities), and their combustion equipment, and the forecasted air pollution control equipment and the potential secondary environmental impacts were previously programmatically analyzed in the December 2015 Final PEA for NOx RECLAIM. This document also analyzed impacts from non-refinery related emission reduction projects (e.g., 11 facilities). During the December 2015 amendments to the NOx RECLAIM program, there were seven refinery-sector facilities in the NOx RECLAIM universe that were not anticipated to retrofit their combustion equipment with NOx controls at that time; thus, these seven refinery-sector facilities were not previously analyzed in the December 2015 Final PEA for NOx RECLAIM. However, the proposed project contains BARCT requirements for combustion equipment operated at these seven refinery-sector facilities and the analysis in this SEA indicates that these facilities, their combustion equipment, the forecasted air pollution control equipment (e.g., new and upgraded

SCRs and/or burner modifications to install ULNBs) that may be implemented to achieve BARCT, and the potential secondary environmental impacts associated with installation and operation of the new and upgraded SCRs and burner replacements with ULNBs, are similar to the previous analysis in the December 2015 Final PEA for NOx RECLAIM. Thus, the proposed project is expected to have the same or similar significant effects that were previously examined in the December 2015 Final PEA for NOx RECLAIM but that will be substantially more severe than what was discussed. The analysis of these impacts is presented in Chapter 4.

Based on the preceding discussion, the baseline that was established at the time the NOP was published for the Draft PEA for NOx RECLAIM (e.g., December 5, 2014) directly corresponds to the currently proposed project since the affected facilities, the type of combustion equipment involved, and the nature of the physical impacts that may occur as a result of implementing the BARCT requirements in PR 1109.1 are the same or similar to the previous analysis in December 2015 Final PEA for NOx RECLAIM. For this reason, the baseline is the project analyzed in the December 2015 Final PEA for NOx RECLAIM.

As such, this SEA analyzes the incremental changes that may occur subsequent to the project analyzed in the December 2015 Final PEA for NOx RECLAIM if proposed project is implemented.

Table 3.1-1 provides a summary of the environmental topic areas previously analyzed in the December 2015 Final PEA for NOx RECLAIM which were concluded to have significant and unavoidable impacts and their applicability to the proposed project.

Table 3.1-1
Applicability of Significant Impacts in the December 2015 Final PEA for NOx RECLAIM to the Proposed Project

ENVIRONMENTAL TOPIC AREA PREVIOUSLY CONCLUDED IN THE DECEMBER 2015 FINAL PEA FOR NOX RECLAIM AS SIGNIFICANT	REMAIN SIGNIFICANT FOR THE PROPOSED PROJECT
Air Quality during construction and GHGs	Overlapping construction activities and the associated emissions occurring at multiple facilities are expected to cause an exceedance in South Coast AQMD's air quality significance thresholds for construction if the proposed project is implemented. The GHG impacts from the combination of amortized construction emissions, plus operational emissions associated with electricity use, water use and conveyance, wastewater generated, and vehicle trips are expected to cause an exceedance in South Coast AQMD's GHG significance threshold if the proposed project is implemented.
Hazards and Hazardous Materials associated with ammonia	The analysis of the proposed project indicates that the deliveries of ammonia, a hazardous material, will be needed to support the function of air pollution control technology (e.g., SCR technology and UltraCat™ with DGS) which are expected to be employed for certain combustion equipment subject to the proposed project.
Hydrology (water demand)	The analysis of the proposed project indicates that potentially significant quantities of additional water will be needed during: 1) hydrotesting of newly installed ammonia storage tanks prior to their operation; and 2) operation of air pollution control equipment that specifically utilize water (e.g., LoTOx™ with WGS).

In addition, the analysis in this SEA independently considered whether the proposed project would result in new significant impacts for any of the other environmental topic areas previously concluded in the December 2015 Final PEA for NOx RECLAIM to have either no significant impacts or less than significant impacts and none were identified. A description and the basis for this conclusion is included in Chapter 4 of this SEA.

The baseline for the analysis in this SEA is the project analyzed in the December 2015 Final PEA for NOx RECLAIM, which provided the regional existing setting for each environmental topic area identified in Table 3.1-1 as having potentially significant adverse environmental impacts. As such, the following subchapters are devoted to describing the regional existing setting for each environmental topic area identified as having potentially significant adverse environmental impacts in Table 3.1-1.

SUBCHAPTER 3.2

AIR QUALITY AND GREENHOUSE GAS EMISSIONS

Criteria Air Pollutants

Greenhouse Gas Emissions

3.2 AIR QUALITY AND GREENHOUSE GAS EMISSIONS

Ambient air quality standards have been adopted at the state and federal levels for criteria air pollutants. In addition, both the state and federal government regulate the release of toxic air contaminants and GHG emissions. Projects within South Coast AQMD's jurisdiction are subject to the rules and regulations imposed by the South Coast AQMD as well as regulations adopted by CARB and U.S. EPA. Federal, state, regional, and local laws, regulations, plans, or guidelines that are potentially applicable to the proposed project are summarized in this section.

3.2.1 CRITERIA AIR POLLUTANTS

It is the responsibility of South Coast AQMD to ensure that state and federal ambient air quality standards (AAQS or standards) are achieved and maintained in its geographical jurisdiction. Health-based air quality standards have been established by California and the federal government for the following criteria air pollutants: ozone (O3), carbon monoxide (CO), nitrogen dioxide (NO2), particulate matter (PM, which includes PM10 and PM2.5), sulfur dioxide (SO2), and lead (Pb). These standards were established to protect sensitive receptors with a margin of safety from adverse health impacts due to exposure to air pollution. The California standards are sometimes more stringent than the federal standards, and in the case of PM10 and SO2, far more stringent. However, for ozone, the current 8-hour California Ambient Air Quality Standard (CAAQS) and the 2015 8-hour National Ambient Air Quality Standard (NAAQS) are at an equivalent level and for PM2.5, the current annual CAAQS and the 2012 annual NAAQS are also at an equivalent level. As a result, the South Coast AQMD relies on the same measures to meet both federal and state ozone and PM2.5 standards. California has also established standards for sulfates, visibility reducing particles, hydrogen sulfide, and vinyl chloride. The state and federal standards for each of these pollutants and their effects on health are summarized in Table 3.2-1.

South Coast AQMD monitors levels of various criteria pollutants at 38 monitoring stations. The 2019 air quality data (the latest data available) from South Coast AQMDs monitoring stations are presented in Tables 3.2-2 through 3.2-8 for the individual criteria air pollutants monitored by South Coast AQMD.

Table 3.2-1
State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	State Standard[a]	Federal Primary Standard[b]	Most Relevant Effects
Ozone (O_3)	1-hour	0.09 ppm (180 µg/m^3)	0.12 ppm	(a) Short-term exposures: 1) Pulmonary function decrements and localized lung edema in humans and animals; and 2) Risk to public health implied by alterations in pulmonary morphology and host defense in animals; (b) Long-term exposures: Risk to public health implied by altered connective tissue metabolism and altered pulmonary morphology in animals after long-term exposures and pulmonary function decrements in chronically exposed humans; (c) Vegetation damage; and (d) Property damage.
	8-hour	0.070 ppm (137 µg/m^3)	0.070 ppm (137 µg/m^3)	
Suspended Particulate Matter (PM10)	24-hour	50 µg/m^3	150 µg/m^3	(a) Excess deaths from short-term exposures and exacerbation of symptoms in sensitive patients with respiratory disease; and (b) Excess seasonal declines in pulmonary function, especially in children.
	Annual Arithmetic Mean	20 µg/m^3	No Federal Standard	
Suspended Particulate Matter (PM2.5)	24-hour	No State Standard	35 µg/m^3	(a) Increased hospital admissions and emergency room visits for heart and lung disease; (b) Increased respiratory symptoms and disease; and (c) Decreased lung functions and premature death.
	Annual Arithmetic Mean	12 µg/m^3	12 µg/m^3	
Carbon Monoxide (CO)	1-Hour	20 ppm (23 mg/m^3)	35 ppm (40 mg/m^3)	(a) Aggravation of angina pectoris and other aspects of coronary heart disease; (b) Decreased exercise tolerance in persons with peripheral vascular disease and lung disease; (c) Impairment of central nervous system functions; and (d) Possible increased risk to fetuses.
	8-Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)	

Table 3.2-1 (concluded)
State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	State Standard[a]	Federal Primary Standard[b]	Most Relevant Effects
Nitrogen Dioxide (NO_2)	1-Hour	0.18 ppm (339 μg/m^3)	0.100 ppm (188 μg/m^3)	(a) Potential to aggravate chronic respiratory disease and respiratory symptoms in sensitive groups; (b) Risk to public health implied by pulmonary and extra-pulmonary biochemical and cellular changes and pulmonary structural changes; and (c) Contribution to atmospheric discoloration.
	Annual Arithmetic Mean	0.030 ppm (57 μg/m^3)	0.053 ppm (100 μg/m^3)	
Sulfur Dioxide (SO_2)	1-Hour	0.25 ppm (655 μg/m^3)	75 ppb (196 μg/m^3)	Broncho-constriction accompanied by symptoms which may include wheezing, shortness of breath and chest tightness, during exercise or physical activity in persons with asthma.
	24-Hour	0.04 ppm (105 μg/m^3)	No Federal Standard	
Sulfates	24-Hour	25 μg/m^3	No Federal Standard	(a) Decrease in ventilatory function; (b) Aggravation of asthmatic symptoms; (c) Aggravation of cardio-pulmonary disease; (d) Vegetation damage; (e) Degradation of visibility; and (f) Property damage
Hydrogen Sulfide (H_2S)	1-Hour	0.03 ppm (42 μg/m^3)	No Federal Standard	Odor annoyance.
Lead (Pb)	30-Day Average	1.5 μg/m^3	No Federal Standard	(a) Increased body burden; and (b) Impairment of blood formation and nerve conduction.
	Calendar Quarter	No State Standard	1.5 μg/m^3	
	Rolling 3-Month Average	No State Standard	0.15 μg/m^3	
Visibility Reducing Particles	8-Hour	Extinction coefficient of 0.23 per kilometer - visibility of ten miles or more due to particles when relative humidity is less than 70 percent.	No Federal Standard	The statewide standard is intended to limit the frequency and severity of visibility impairment due to regional haze. This is a visibility-based standard not a health-based standard. Nephelometry and AISI Tape Sampler; instrumental measurement on days when relative humidity is less than 70 percent.
Vinyl Chloride	24-Hour	0.01 ppm (26 μg/m^3)	No Federal Standard	Highly toxic and a known carcinogen that causes a rare cancer of the liver.
ppb = parts per billion parts of air, by volume ppm = parts per million parts of air, by volume			μg/m3 = micrograms per cubic meter mg/m3 = milligrams per cubic meter	

[a] The California ambient air quality standards for O3, CO, SO2 (1-hour and 24-hour), NO2, PM10, and PM2.5 are values not to be exceeded. All other California standards shown are values not to be equaled or exceeded.

[b] The national ambient air quality standards, other than O3 and those based on annual averages are not to be exceeded more than once a year. The O_3 standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above the standards is equal to or less than one.

Carbon Monoxide

CO is a primary pollutant, meaning that it is directly emitted into the air, not formed in the atmosphere by chemical reaction of precursors, as is the case with ozone and other secondary pollutants. Ambient concentrations of CO in the Basin exhibit large spatial and temporal variations due to variations in the rate at which CO is emitted and in the meteorological conditions that govern transport and dilution. Unlike ozone, CO tends to reach high concentrations in the fall and winter months. The highest concentrations frequently occur on weekdays at times consistent with rush hour traffic and late night during the coolest, most stable portion of the day.

Individuals with a deficient blood supply to the heart are the most susceptible to the adverse effects of CO exposure. The effects observed include earlier onset of chest pain with exercise and electrocardiograph changes indicative of worsening oxygen supply to the heart. Inhaled CO has no direct toxic effect on the lungs but exerts its effect on tissues by interfering with oxygen transport by competing with oxygen to combine with hemoglobin present in the blood to form carboxyhemoglobin (COHb). Hence, conditions with an increased demand for oxygen supply can be adversely affected by exposure to CO. Individuals most at risk include patients with diseases involving heart and blood vessels, fetuses, and patients with chronic hypoxemia (oxygen deficiency) as seen in high altitudes. Reductions in birth weight and impaired neurobehavioral development have been observed in animals chronically exposed to CO resulting in COHb levels similar to those observed in smokers. Recent studies have found increased risks for adverse birth outcomes with exposure to elevated CO levels. These include preterm births and heart abnormalities.[1,2,3]

On August 12, 2011, U.S. EPA issued a decision to retain the existing NAAQS for CO, determining that those standards provided the required level of public health protection. However, U.S. EPA added a monitoring requirement for near-road CO monitors in urban areas with population of one million or more, utilizing stations that would be implemented to meet the 2010 NO2 near-road monitoring requirements. The two new CO monitors are at the I-5 near-road site, located in Orange County near Anaheim, and the I-10 near-road site, located near Etiwanda Avenue in San Bernardino County near Ontario, Rancho Cucamonga, and Fontana.

As summarized in Table 3.2-2, CO concentrations were measured at 24 locations in the SCAB and neighboring SSAB in 2019 but did not exceed the state or federal standards in 2019. The highest 1-hour average carbon monoxide concentration recorded was 3.8 ppm (at the South Central Los Angeles County station), less than the federal and state 1-hour carbon monoxide standards of 35 ppm and 20 ppm, respectively. The highest 8-hour average carbon monoxide concentration recorded was 3.2 ppm (at the South Central Los Angeles County station), less than the federal and state 8-hour carbon monoxide standards of 9.0 ppm. All areas within the South Coast AQMD's jurisdiction are in attainment for both the federal and state 1-hour and 8-hour carbon monoxide standards.

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[1] U.S. Environmental Protection Agency. 2020. Criteria Air Pollutants. Accessed December 10, 2020. https://www.epa.gov/criteria-air-pollutants.

[2] South Coast AQMD. 2015. Health Effects of Air Pollution. http://www.aqmd.gov/docs/default-source/publications/brochures/the-health-effects-of-air-pollution-brochure.pdf

[3] South Coast AQMD. 2005, May. Guidance Document for Addressing Air Quality Issues in General Plans and Local Planning. https://www.aqmd.gov/home/research/guidelines/planning-guidance/guidance-document

Table 3.2-2
South Coast AQMD – 2019 Air Quality Data – CO

CARBON MONOXIDE (CO)[a]				
Source Receptor Area No.	**Location of Air Monitoring Station**	**No. Days of Data**	**Max. Conc. in ppm 1-hour**	**Max. Conc. in ppm, 8-hour**
LOS ANGELES COUNTY				
1	Central Los Angeles	364	2.0	1.6
2	Northwest Coastal Los Angeles County	364	1.9	1.2
3	Southwest Coastal Los Angeles County	364	1.8	1.3
4	South Coastal Los Angeles County 1	--	--	--
4	South Coastal Los Angeles County 2	--	--	--
4	South Coastal Los Angeles County 3	340	3.0	2.1
4	I-710 Near Road[##]	--	--	--
6	West San Fernando Valley	363	2.6	2.2
8	West San Gabriel Valley	361	1.5	1.2
9	East San Gabriel Valley 1	361	1.6	1.1
9	East San Gabriel Valley 2	360	1.2	0.8
10	Pomona/Walnut Valley	364	1.7	1.3
11	South San Gabriel Valley	354	1.9	1.5
12	South Central Los Angeles County	363	3.8	3.2
13	Santa Clarita Valley	359	1.5	1.2
ORANGE COUNTY				
16	North Orange County	364	2.6	1.2
17	Central Orange County	363	2.4	1.3
17	I-5 Near Road[##]	350	2.6	1.6
18	North Coastal Orange County	--	--	--
19	Saddleback Valley	363	1.0	0.8
RIVERSIDE COUNTY				
22	Corona/Norco Area	--	--	--
23	Metropolitan Riverside County 1	364	1.5	1.2
23	Metropolitan Riverside County 3	364	2.0	1.3
24	Perris Valley	--	--	--
25	Lake Elsinore	364	1.6	0.7
26	Temecula Valley	--	--	--
29	San Gorgonio Pass	--	--	--
30	Coachella Valley 1**	360	1.3	0.7
30	Coachella Valley 2**	--	--	--
30	Coachella Valley 3**	--	--	--
SAN BERNARDINO COUNTY				
32	Northwest San Bernardino Valley	337	1.5	1.1
33	I-10 Near Road[##]	364	1.5	1.1
33	CA-60 Near Road[##]	--	--	--
34	Central San Bernardino Valley 1	359	2.7	1.0
34	Central San Bernardino Valley 2	352	1.3	1.1
35	East San Bernardino Valley	--	--	--
37	Central San Bernardino Mountains	--	--	--
38	East San Bernardino Mountains	--	--	--

Table 3.2-2 (Continued)
South Coast AQMD – 2019 Air Quality Data – CO

CARBON MONOXIDE (CO)a				
Source Receptor Area No.	**Location of Air Monitoring Station**	**No. Days of Data**	**Max. Conc. in ppm 1-hour**	**Max. Conc. in ppm, 8-hour**
DISTRICT MAXIMUM			**3.8**	**3.2**
SOUTH COAST AIR BASIN			**3.8**	**3.2**

ppm = parts per million
-- Pollutant not monitored
*Incomplete Data
**Salton Sea Air Basin
[##] Four near-road sites measuring one or more of the pollutants PM2.5, CO, and/or NO2 are operating near the following freeways: I-1, I-10, CA-60, and I-710.
[a] The federal 8-hour standard (8-hour average CO > 9 ppm) and state 8-hour standard (8-hour average CO > 9.0 ppm) were not exceeded. The federal and state 1-hour standards (35 ppm and 20 ppm) were not exceeded either.
[b] District Maximum is the maximum value calculated at any station in the South Coast AQMD jurisdiction.
[c] Concentrations are the maximum value observed at any station in the SCAB. Number of daily exceedances are the total number of days that the indicated concentration is exceeded at any station in the SCAB.

Ozone

Ozone (O3), a colorless gas with a sharp odor, is a highly reactive form of oxygen. High ozone concentrations exist naturally in the stratosphere. Some mixing of stratospheric ozone downward through the troposphere to the earth's surface does occur; however, the extent of ozone transport is limited. At the earth's surface in sites remote from urban areas ozone concentrations are normally very low (e.g., from 0.03 ppm to 0.05 ppm).

Ozone is highly reactive with organic materials, causing damage to living cells and ambient ozone concentrations in the Basin are frequently sufficient to cause health effects. Ozone enters the human body primarily through the respiratory tract and causes respiratory irritation and discomfort, makes breathing more difficult during exercise, and reduces the respiratory system's ability to remove inhaled particles and fight infection. Individuals exercising outdoors, children, and people with preexisting lung disease, such as asthma and chronic pulmonary lung disease, are considered to be the most susceptible subgroups for ozone effects. Short-term exposures (lasting for a few hours) to ozone at levels typically observed in Southern California can result in breathing pattern changes, reduction of breathing capacity, increased susceptibility to infections, inflammation of the lung tissue, and some immunological changes. In recent years, a correlation between elevated ambient ozone levels and increases in daily hospital admission rates, as well as mortality, has also been reported. An increased risk for asthma has been found in children who participate in multiple sports and live in high ozone communities. Elevated ozone levels are also associated with increased school absences. Ozone exposure under exercising conditions is known to increase the severity of the previously mentioned observed responses. Animal studies suggest that exposures to a combination of pollutants which include ozone may be more toxic than exposure to ozone alone. Although lung volume and resistance changes observed after a single exposure diminish with repeated exposures, biochemical and cellular changes appear to persist, which can lead to subsequent lung structural changes.[4,5,6]

[4] U.S. Environmental Protection Agency. 2020. Criteria Air Pollutants. Accessed December 10, 2020. https://www.epa.gov/criteria-air-pollutants.
[5] South Coast AQMD. 2015. Health Effects of Air Pollution. http://www.aqmd.gov/docs/default-source/publications/brochures/the-health-effects-of-air-pollution-brochure.pdf
[6] South Coast AQMD. 2005, May. Guidance Document for Addressing Air Quality Issues in General Plans and Local Planning. https://www.aqmd.gov/home/research/guidelines/planning-guidance/guidance-document

As summarized in Table 3.2-3, ozone concentrations were measured at 28 locations in the SCAB and the Coachella Valley portion of the SSAB in 2019. Maximum ozone concentrations for all areas monitored were below the stage 1 episode level (0.20 ppm) and below the health advisory level (0.15 ppm). All counties in the Basin, as well as the Coachella Valley, exceeded the level of the 2015 8-hour ozone NAAQS (0.070 ppm), the former 2008 8-hour ozone NAAQS (0.075 ppm), and/or the 1997 8-hour ozone NAAQS (0.08 ppm) in 2019. While not all stations had days exceeding the previous 8-hour standards, all monitoring stations except two had at least one day over the 2015 federal ozone standard (70 ppb).

Maximum 1-hour average and 4^{th} highest 8-hour average ozone concentrations were 0.137 ppm and 0.106 ppm, respectively (at the East San Bernardino Valley station), greater than the federal 1-hour and 8-hour ozone NAAQS of 0.12 ppm and 0.070 ppm, respectively. The federal 8-hour standard is met at an air quality monitor when the 3-year average of the annual fourth-highest daily maximum 8-hour average is less than 0.070 ppm. The maximum 1-hour concentration also exceeded the state 1-hour ozone standard of 0.09 ppm. All areas within South Coast AQMD's jurisdiction are in nonattainment for both the federal and state 1-hour and 8-hour ozone standards.

Table 3.2-3
South Coast AQMD – 2019 Air Quality Data – O3

OZONE (O3)										
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. in ppm 1-hr	Max. Conc. in ppm 8-hr	4th High Conc. ppm 8-hr	No. Days Standard Exceeded				
						Federal (ppm)			State (ppm)	
						Old > 0.124 1-hr	Current > 0.070 8-hr*	2008 > 0.075 8-hr	Current > 0.09 1-hr	Current > 0.070 8-hr
LOS ANGELES COUNTY										
1	Central LA	364	0.085	0.080	0.065	0	2	1	0	2
2	Northwest Coastal LA County	360	0.086	0.075	0.064	0	1	0	0	1
3	Southwest Coastal LA County	365	0.082	0.067	0.060	0	0	0	0	0
4	South Coastal LA County 1	--	--	--	--	--	--	--	--	--
4	South Coastal LA County 2	--	--	--	--	--	--	--	--	--
4	South Coastal LA County 3	343	0.074	0.064	0.055	0	0	0	0	0
4	I-710 Near Road[##]	--	--	--	--	--	--	--	--	--
6	West San Fernando Valley	267	0.101	0.087	0.076	0	6	4	1	6
8	West San Gabriel Valley	302	0.120	0.098	0.086	0	12	8	4	12
9	East San Gabriel Valley 1	362	0.123	0.094	0.090	0	39	21	34	39
9	East San Gabriel Valley 2	356	0.130	0.102	0.097	1	58	38	46	58
10	Pomona/Walnut Valley	365	0.096	0.083	0.077	0	12	4	1	12
11	South San Gabriel Valley	364	0.108	0.091	0.073	0	7	3	5	7
12	South Central LA County	363	0.100	0.079	0.064	0	1	1	1	1
13	Santa Clarita Valley	359	0.128	0.106	0.101	1	56	42	34	56
ORANGE COUNTY										
16	North Orange County	364	0.107	0.094	0.074	0	6	3	2	6
17	Central Orange County	365	0.096	0.082	0.064	0	1	1	1	1
17	I-5 Near Road[##]	--	--	--	--	--	--	--	--	--
18	North Coastal Orange County	--	--	--	--	--	--	--	--	--
19	Saddleback Valley	365	0.106	0.087	0.082	0	11	7	3	11
RIVERSIDE COUNTY										
22	Corona/Norco Area	--	--	--	--	--	--	--	--	--
23	Metropolitan Riverside County 1	360	0.123	0.096	0.092	0	59	37	24	59
23	Metropolitan Riverside County 3	365	0.131	0.099	0.096	2	64	42	26	64
24	Perris Valley	365	0.118	0.095	0.090	0	64	38	26	64
25	Lake Elsinore	365	0.108	0.089	0.079	0	28	11	4	28
26	Temecula Valley	365	0.091	0.079	0.074	0	6	2	0	6
29	San Gorgonio Pass	365	0.119	0.096	0.093	0	59	37	24	59
30	Coachella Valley 1**	364	0.100	0.084	0.083	0	34	17	5	34
30	Coachella Valley 2**	365	0.103	0.087	0.083	0	43	15	4	43
30	Coachella Valley 3**	--	--	--	--	--	--	--	--	--
SAN BERNARDINO COUNTY										
32	Northwest San Bernardino Valley	338	0.131	0.107	0.097	1	52	34	31	52
33	I-10 Near Road[##]	--	--	--	--	--	--	--	--	--
33	CA-60 Near Road[##]	--	--	--	--	--	--	--	--	--
34	Central San Bernardino Valley 1	364	0.124	0.109	0.097	0	67	46	41	67
34	Central San Bernardino Valley 2	354	0.127	0.114	0.103	2	96	73	63	96
35	East San Bernardino Valley	364	0.137	0.117	0.106	8	109	88	73	109
37	Central San Bernardino Mountains	365	0.129	0.112	0.106	2	99	79	53	99
38	East San Bernardino Mountains	--	--	--	--	--	--	--	--	--
DISTRICT MAXIMUM			**0.137**	**0.117**	**0.106**	**8**	**109**	**88**	**73**	**109**
SOUTH COAST AIR BASIN			**0.137**	**0.117**	**0.106**	**10**	**126**	**101**	**82**	**126**

ppm = parts per million of air, by volume
-- = Pollutant not monitored
*Incomplete data
**Salton Sea Air Basin
[##] = Four near-road sites measuring one or more of the pollutants PM2.5, CO, and/or NO2 are operating near the following freeways: I-5, I-10, CA-60, and I-710.
[a] District Maximum is the maximum value calculated at any station in the South Coast AQMD jurisdiction.
[b] Concentrations are the maximum value observed at any station in the SCAB. Number of daily exceedances are the total number of days that the indicated concentration is exceeded at any station in the SCAB.

Nitrogen Dioxide

NO2 is a reddish-brown gas with a bleach-like odor. Nitric oxide (NO) is a colorless gas, formed from the nitrogen (N2) and oxygen (O2) in air under conditions of high temperature and pressure which are generally present during combustion of fuels; NO reacts rapidly with the oxygen in air to form NO2. NO2 is responsible for the brownish tinge of polluted air. The two gases, NO and NO2, are referred to collectively as NOx. In the presence of sunlight, NO2 reacts to form nitric oxide and an oxygen atom. The oxygen atom can react further to form ozone, via a complex series of chemical reactions involving hydrocarbons. Nitrogen dioxide may also react to form nitric acid (HNO3) which reacts further to form nitrates, components of PM2.5 and PM10.

Population-based studies suggest that an increase in acute respiratory illness, including infections and respiratory symptoms in children (not infants), is associated with long-term exposures to NO2 at levels found in homes with gas stoves, which are higher than ambient levels found in Southern California. Increase in resistance to air flow and airway contraction is observed after short-term exposure to NO2 in healthy subjects. Larger decreases in lung functions are observed in individuals with asthma and/or chronic obstructive pulmonary disease (e.g., chronic bronchitis, emphysema) than in healthy individuals, indicating a greater susceptibility of these subgroups. More recent studies have found associations between NO2 exposures and cardiopulmonary mortality, decreased lung function, respiratory symptoms, and emergency room asthma visits. In animals, exposure to levels of NO2 considerably higher than ambient concentrations result in increased susceptibility to infections, possibly due to the observed changes in cells involved in maintaining immune functions. The severity of lung tissue damage associated with high levels of ozone exposure increases when animals are exposed to a combination of ozone and NO2.[7,8,9]

With the revised NO2 federal standard in 2010, near-road NO2 measurements were required to be phased in for larger cities. The four near-road monitoring stations are: 1) I-5 near-road, located in Orange County near Anaheim; 2) I-710 near-road, located at Long Beach Blvd. in Los Angeles County near Compton and Long Beach; 3) State Route 60 (CA-60) near-road, located west of Vineyard Avenue near the San Bernardino/Riverside County border near Ontario, Mira Loma, and Upland; and 4) I-10 near-road, located near Etiwanda Avenue in San Bernardino County near Ontario, Rancho Cucamonga, and Fontana.

As summarized in Table 3.2-4, NO2 concentrations were measured at 26 locations in the SCAB and neighboring SSAB in 2019 but did not exceed the federal or state standards in 2019. The highest 1-hour average nitrogen dioxide concentration recorded was 97.7 ppb (at the I-710 Near Road station), less than the federal and state 1-hour nitrogen dioxide standards of 100 ppb and 180 ppb, respectively. The highest annual average nitrogen dioxide concentration recorded was 29.0 ppb (at the CA-60 Near Road station), less than the federal and state annual nitrogen dioxide standards of 53 ppb and 30 ppb, respectively. All areas within South Coast AQMD’s jurisdiction are in attainment for both the federal and state 1-hour and annual nitrogen dioxide standards.

7 U.S. Environmental Protection Agency. 2020. Criteria Air Pollutants. Accessed December 10, 2020. https://www.epa.gov/criteria-air-pollutants

8 South Coast AQMD. 2015. Health Effects of Air Pollution. http://www.aqmd.gov/docs/default-source/publications/brochures/the-health-effects-of-air-pollution-brochure.pdf

9 South Coast AQMD. 2005, May. Guidance Document for Addressing Air Quality Issues in General Plans and Local Planning. https://www.aqmd.gov/home/research/guidelines/planning-guidance/guidance-document

Table 3.2-4
South Coast AQMD – 2019 Air Quality Data – NO2

NITROGEN DIOXIDE (NO2)[a]					
Source Receptor Area No.	**Location of Air Monitoring Station**	**No. Days of Data**	**Max. Conc. in ppb 1-hour**	**98th Percentile Conc. in ppb 1-hour**	**Annual Average AAM Conc. ppb**
LOS ANGELES COUNTY					
1	Central LA	365	69.7	55.5	17.7
2	Northwest Coastal LA County	365	48.8	43.0	9.7
3	Southwest Coastal LA County	363	56.6	48.9	9.5
4	South Coastal LA County 1	--	--	--	--
4	South Coastal LA County 2	--	--	--	--
4	South Coastal LA County 3	255	71.8	56.3	16.2
4	I-710 Near Road##	365	97.7	78.3	22.8
6	West San Fernando Valley	365	64.4	43.8	10.7
8	West San Gabriel Valley	361	59.1	50.6	13.2
9	East San Gabriel Valley 1	365	59.7	49.8	13.7
9	East San Gabriel Valley 2	360	52.9	36.5	8.6
10	Pomona/Walnut Valley	365	64.4	57.8	17.9
11	South San Gabriel Valley	364	61.8	55.1	17.6
12	South Central LA County	363	70.0	52.8	14.1
13	Santa Clarita Valley	357	46.3	35.3	9.1
ORANGE COUNTY					
16	North Orange County	362	59.4	44.5	12.1
17	Central Orange County	365	59.4	49.2	12.7
17	I-5 Near Road##	365	59.4	50.4	19.2
18	North Coastal Orange County	--	--	--	--
19	Saddleback Valley	--	--	--	--
RIVERSIDE COUNTY					
22	Corona/Norco Area	--	--	--	--
23	Metropolitan Riverside County 1	365	56.0	52.8	13.5
23	Metropolitan Riverside County 3	346	56.0	49.4	12.2
24	Perris Valley	--	--	--	--
25	Lake Elsinore	365	38.0	33.3	6.8
26	Temecula Valley	--	--	--	--
29	San Gorgonio Pass	364	56.0	43.3	7.5
30	Coachella Valley 1**	361	41.4	32.2	7.3
30	Coachella Valley 2**	--	--	--	--
30	Coachella Valley 3**	--	--	--	--
SAN BERNARDINO COUNTY					
32	Northwest San Bernardino Valley	328	57.9	46.4	14.0
33	I-10 Near Road##	346	86.3	70.5	27.6
33	CA-60 Near Road##	364	87.7	73.9	29.0
34	Central San Bernardino Valley 1	365	76.1	57.7	17.2
34	Central San Bernardino Valley 2	352	59.3	46.3	14.3
35	East San Bernardino Valley	--	--	--	--
37	Central San Bernardino Mountains	--	--	--	--
38	East San Bernardino Mountains	--	--	--	--

Table 3.2-4 (Continued)
South Coast AQMD – 2019 Air Quality Data – NO2

NITROGEN DIOXIDE (NO2)[a]					
Source Receptor Area No.	**Location of Air Monitoring Station**	**No. Days of Data**	**Max. Conc. in ppb 1-hour**	**98th Percentile Conc. in ppb 1-hour**	**Annual Average AAM Conc. ppb**
DISTRICT MAXIMUM			**97.7**	**78.3**	**29.0**
SOUTH COAST AIR BASIN			**97.7**	**78.3**	**29.0**

ppb = parts per billion
AAM = Annual Arithmetic Mean
-- Pollutant not monitored
*Incomplete data
**Salton Sea Air Basin
[##] Four near-road sites measuring one or more of the pollutants PM2.5, CO, and/or NO2 are operating near the following freeways: I-1, I-10, CA-60, and I-710.
[a] The NO2 federal 1-hour standard is 100 ppb and the annual standard is annual arithmetic mean NO2 > 0.0534 ppm (53.4 ppb). The state 1-hour and annual standards are 0.18 ppm (180 ppb) and 0.030 ppm (30 ppb).
[b] District Maximum is the maximum value calculated at any station in the South Coast AQMD jurisdiction.
[c] Concentrations are the maximum value observed at any station in the SCAB. Number of daily exceedances are the total number of days that the indicated concentration is exceeded at any station in the SCAB.

Sulfur Dioxide

SO2 is a colorless gas with a sharp odor. It reacts in the air to form sulfuric acid (H2SO4), which contributes to acid precipitation, and sulfates, which are components of PM10 and PM2.5. Most of the SO2 emitted into the atmosphere is produced by burning sulfur-containing fuels.

Exposure of a few minutes to low levels of SO2 can result in airway constriction in some asthmatics. All asthmatics are sensitive to the effects of SO2. In asthmatics, increase in resistance to air flow, as well as reduction in breathing capacity leading to severe breathing difficulties, is observed after acute higher exposure to SO2. In contrast, healthy individuals do not exhibit similar acute responses even after exposure to higher concentrations of SO2. Animal studies suggest that despite SO2 being a respiratory irritant, it does not cause substantial lung injury at ambient concentrations. However, very high levels of exposure can cause lung edema (fluid accumulation), lung tissue damage, and sloughing off of cells lining the respiratory tract. Some population-based studies indicate that the mortality and morbidity effects associated with fine particles show a similar association with ambient SO2 levels. In these studies, efforts to separate the effects of SO2 from those of fine particles have not been successful. It is not clear whether the two pollutants act synergistically or one pollutant alone is the predominant factor.[10,11,12]

As summarized in Table 3.2-5, SO2 concentrations were measured at five locations in 2019. No exceedances of 1-hour federal or state standards of 75 ppb and 250 ppb respectively, for sulfur dioxide occurred in 2019 at any of the five locations monitored the Basin. The maximum 1-hour SO2 concentration was 10.0 ppb (recorded at the Central Los Angeles County station). The 99th percentile of 1-hour SO2 concentration was 7.7 ppb (recorded at the South Coastal Los Angeles County 3 station). Though SO2 concentrations remain well below the standards, SO2 is a precursor to sulfate, which is a component of fine particulate matter, PM10, and PM2.5. Historical

[10] U.S. Environmental Protection Agency. 2020. Criteria Air Pollutants. Accessed December 10, 2020. https://www.epa.gov/criteria-air-pollutants.
[11] South Coast AQMD. 2015. Health Effects of Air Pollution. http://www.aqmd.gov/docs/default-source/publications/brochures/the-health-effects-of-air-pollution-brochure.pdf
[12] South Coast AQMD. 2005. May. Guidance Document for Addressing Air Quality Issues in General Plans and Local Planning. https://www.aqmd.gov/home/research/guidelines/planning-guidance/guidance-document

measurements showed concentrations to be well below standards and monitoring has been discontinued at other stations. All areas within South Coast AQMD's jurisdiction are in attainment for both the federal and state 1-hour sulfur dioxide standards.

Table 3.2-5
South Coast AQMD – 2019 Air Quality Data – SO2

SULFUR DIOXIDE (SO2)[a]				
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Maximum Conc. ppb, 1-hour	99th Percentile Conc. ppb, 1-hour
LOS ANGELES COUNTY				
1	Central LA	365	10.0	2.3
2	Northwest Coastal LA County	--	--	--
3	Southwest Coastal LA County	365	8.2	3.7
4	South Coastal LA County 1	--	--	--
4	South Coastal LA County 2	--	--	--
4	South Coastal LA County 3	344	8.9	7.7
4	I-710 Near Road##	--	--	--
6	West San Fernando Valley	--	--	--
8	West San Gabriel Valley	--	--	--
9	East San Gabriel Valley 1	--	--	--
9	East San Gabriel Valley 2	--	--	--
10	Pomona/Walnut Valley	--	--	--
11	South San Gabriel Valley	--	--	--
12	South Central LA County	--	--	--
13	Santa Clarita Valley	--	--	--
ORANGE COUNTY				
16	North Orange County	--	--	--
17	Central Orange County	--	--	--
17	I-5 Near Road##	--	--	--
18	North Coastal Orange County	--	--	--
19	Saddleback Valley	--	--	--
RIVERSIDE COUNTY				
22	Corona/Norco Area	--	--	--
23	Metropolitan Riverside County 1	365	1.8	1.4
23	Metropolitan Riverside County 3	--	--	--
24	Perris Valley	--	--	--
25	Lake Elsinore	--	--	--
26	Temecula Valley	--	--	--
29	San Gorgonio Pass	--	--	--
30	Coachella Valley 1**	--	--	--
30	Coachella Valley 2**	--	--	--
30	Coachella Valley 3**	--	--	--
SAN BERNARDINO COUNTY				
32	Northwest San Bernardino Valley	--	--	--
33	I-10 Near Road##	--	--	--
33	CA-60 Near Road##	--	--	--
34	Central San Bernardino Valley 1	358	2.4	1.9
34	Central San Bernardino Valley 2	--	--	--
35	East San Bernardino Valley	--	--	--
37	Central San Bernardino Mountains	--	--	--
38	East San Bernardino Mountains	--	--	--

Table 3.2-5 (Continued)
South Coast AQMD – 2019 Air Quality Data – SO2

SULFUR DIOXIDE (SO2)[a]				
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Maximum Conc. ppb, 1-hour	99th Percentile Conc. ppb, 1-hour
DISTRICT MAXIMUM			**10.0**	**7.7**
SOUTH COAST AIR BASIN			**10.0**	**7.7**

ppb = parts per billion
-- = Pollutant not monitored
*Incomplete data
** Salton Sea Air Basin
[##] Four near-road sites measuring one or more of the pollutants PM2.5, CO, and/or NO2 are operating near the following freeways: I-5, I-10, CA-60, and I-710.
[a] The NO2 federal 1-hour standard is 100 ppb and the annual standard is annual arithmetic mean NO2 > 0.0534 ppm (53.4 ppb). The state 1-hour and annual standards are 0.18 ppm (180 ppb) and 0.030 ppm (30 ppb).
[b] District Maximum is the maximum value calculated at any station in the South Coast AQMD jurisdiction.
[c] Concentrations are the maximum value observed at any station in the SCAB. Number of daily exceedances are the total number of days that the indicated concentration is exceeded at any station in the SCAB.

Particulate Matter (PM10 and PM2.5)

Of great concern to public health are the particles small enough to be inhaled into the deepest parts of the lung. Respirable particles (particulate matter less than about 10 micrometers in diameter (PM10)) can accumulate in the respiratory system and aggravate health problems such as asthma, bronchitis, and other lung diseases. Children, the elderly, exercising adults, and those suffering from asthma are especially vulnerable to adverse health effects of particulate matter.

A consistent correlation between elevated ambient fine particulate matter (PM2.5) levels and an increase in mortality rates, respiratory infections, number and severity of asthma attacks, and the number of hospital admissions has been observed in different parts of the United States and various areas around the world. Studies have reported an association between long-term exposure to air pollution dominated by PM2.5 and increased mortality, reduction in life-span, and an increased mortality from lung cancer. Daily fluctuations in PM2.5 concentrations have also been related to hospital admissions for acute respiratory conditions, to school and kindergarten absences, to a decrease in respiratory function in normal children, and to increased medication use in children and adults with asthma. Studies have also shown lung function growth in children is reduced with long-term exposure to particulate matter. In addition to children, the elderly and people with preexisting respiratory and/or cardiovascular disease appear to be more susceptible to the effects of PM10 and PM2.5.[13,14,15]

As summarized in Table 3.2-6, PM10 concentrations were measured at 22 locations in 2019. While the Coachella Valley Portion of the SSAB is in nonattainment, the SCAB has remained in attainment for the federal 24-hour PM10 standard (150 $\mu g/m^3$) since 2006, and it was not exceeded in 2019. The maximum 24-hour PM10 concentration of 154 $\mu g/m^3$ was recorded at the Coachella Valley station, but this high reading was attributed to high winds and is excluded in accordance with the U.S. EPA Exceptional Event Rule. Also, due to rounding considerations, the federal

[13] U.S. Environmental Protection Agency. 2020. Criteria Air Pollutants. Accessed December 10, 2020. https://www.epa.gov/criteria-air-pollutants.
[14] South Coast AQMD. 2015. Health Effects of Air Pollution. http://www.aqmd.gov/docs/default-source/publications/brochures/the-health-effects-of-air-pollution-brochure.pdf
[15] South Coast AQMD. 2005, May. Guidance Document for Addressing Air Quality Issues in General Plans and Local Planning. https://www.aqmd.gov/home/research/guidelines/planning-guidance/guidance-document

standard is technically 155 µg/m^3. The state 24-hour PM10 (50 µg/m^3) standard was exceeded at several of the monitoring stations. All areas within South Coast AQMD's jurisdiction are in nonattainment for the state 24-hour PM10 standard, which was exceeded at several of the monitoring stations in 2019.

The maximum annual average PM10 concentration of 43.1 µg/m^3 was recorded at the Metropolitan Riverside County station. The federal annual PM10 standard has been revoked. The state annual PM10 standard (20 µg/m^3) was exceeded in most stations in each county in the Basin and in the Coachella Valley. All areas within South Coast AQMD's jurisdiction are in nonattainment for the state annual PM10 standard, which was exceeded at most stations in each county in the South Coast Air Basin and in the Coachella Valley in 2019.

On December 14, 2012, U.S. EPA strengthened the annual NAAQS for PM2.5 to 12 µg/m^3 and, as part of the revisions, a requirement was added to monitor near the most heavily trafficked roadways in large urban areas. Particle pollution is expected to be higher along these roadways because of direct emissions from cars and heavy-duty diesel trucks and buses. South Coast AQMD installed the two required PM2.5 monitors at locations selected based upon the heavy-duty diesel traffic, which are: 1) I-710, located at Long Beach Blvd. in Los Angeles County near Compton and Long Beach; and 2) State Route 60 (SR-60) near-road, located west of Vineyard Avenue near the San Bernardino/Riverside County border near Ontario, Mira Loma, and Upland.

As summarized in Table 3.2-7, PM2.5 concentrations were measured at 19 locations in 2019. While the Coachella Valley Portion of the SSAB is in attainment, the SCAB is in nonattainment for federal and state PM2.5 standards. The maximum 98th percentile 24-hour PM2.5 concentration of 36.2 µg/m^3 was recorded at the Metropolitan Riverside County station, greater than the federal 24-hour PM2.5 standard of 35 µg/m^3. There is no state 24-hour standard for PM2.5. The maximum annual average PM2.5 concentration of 12.70 µg/m^3 was recorded at the CA-60 Near Road station, greater than the federal and state annual PM2.5 standard of 12 µg/m^3.

Table 3.2-6
South Coast AQMD – 2019 Air Quality Data – PM10

SUSPENDED PARTICULATE MATTER PM10[a]						
Source Receptor Area No.	**Location of Air Monitoring Station**	**No. Days of Data**	**Max. Conc. µg/m³, 24-hour**	**No. (%) Samples Exceeding Standard: Federal > 150 µg/m³, 24-hour**	**No. (%) Samples Exceeding Standard: State > 50 µg/m³, 24-hour**	**Annual Average AAM Conc.[b] µg/m³**
LOS ANGELES COUNTY						
1	Central LA	9	62	0	3 (6%)	25.5
2	Northwest Coastal LA County	--	--	--	--	--
3	Southwest Coastal LA County	59	62	0	2 (3%)	19.2
4	South Coastal LA County 1	--	--	--	--	--
4	South Coastal LA County 2	60	72	0	2 (3%)	21.0
4	South Coastal LA County 3	58	74	0	3 (5%)	26.9
4	I-710 Near Road##	--	--	--	--	--
6	West San Fernando Valley	--	--	--	--	--
8	West San Gabriel Valley	--	--	--	--	--
9	East San Gabriel Valley 1	61	82	0	4 (7%)	28.1
9	East San Gabriel Valley 2	308	97	0	3 (1%)	20.8
10	Pomona/Walnut Valley	--	--	--	--	--
11	South San Gabriel Valley	--	--	--	--	--
12	South Central LA County	--	--	--	--	--
13	Santa Clarita Valley	60	62	0	1 (2%)	18.4
ORANGE COUNTY						
16	North Orange County	--	--	--	--	--
17	Central Orange County	364	127	0	13 (4%)	21.9
17	I-5 Near Road##	--	--	--	--	--
18	North Coastal Orange County	--	--	--	--	--
19	Saddleback Valley	60	45	0	0	16.6
RIVERSIDE COUNTY						
22	Corona/Norco Area	--	--	--	--	--
23	Metropolitan Riverside County 1	120	99	0	21 (18%)	34.4
23	Metropolitan Riverside County 3	362	143	0	130 (36%)	43.1
24	Perris Valley	61	97	0	4 (7%)	25.3
25	Lake Elsinore	301	93	0	5 (2%)	18.7
26	Temecula Valley	--	--	--	--	--
29	San Gorgonio Pass	56	63	0	2 (4%)	17.9
30	Coachella Valley 1**	346	75	0	5 (1%)	19.5
30	Coachella Valley 2**	361	141	0	27 (7%)	27.8
30	Coachella Valley 3**	324	154	0	44 (14%)	33.3
SAN BERNARDINO COUNTY						
32	Northwest San Bernardino Valley	306	125	0	7 (2%)	28.1
33	I-10 Near Road##	--	--	--	--	--
33	CA-60 Near Road##	--	--	--	--	--
34	Central San Bernardino Valley 1	61	88	0	12 (20%)	34.8
34	Central San Bernardino Valley 2	269	112	0	36 (13%)	29.9
35	East San Bernardino Valley	59	44	0	0	21.2
37	Central San Bernardino Mountains	54	38	0	0	16.1
38	East San Bernardino Mountains	--	--	--	--	--
DISTRICT MAXIMUM			**154**	**0**	**130**	**43.1**
SOUTH COAST AIR BASIN			**143**	**0**	**137**	**43.1**

µg/m³= micrograms per cubic meter of air
AAM = Annual Arithmetic Mean
-- Pollutant not monitored
*Incomplete Data
**Salton Sea Air Basin

Four near-road sites measuring one or more of the pollutants PM2.5, CO, and/or NO2 are operating near the following freeways: I-1, I-10, CA-60, and I-710.
\+ High PM10 (≥ 155 µg/m³) data recorded in Coachella Valley (due to high winds) and the Basin (due to Independence Day fireworks) are excluded in accordance with the U.S. EPA Exceptional Event Rule.

[a] PM10 statistics listed above are based on combined Federal Reference Method (FRM) and Federal Equivalent Method (FEM) data.
[b] State annual average (AAM) PM10 standard is > 20 µg/m3. Federal annual PM10 standard (AAM > 50 µg/m3) was revoked in 2006.
[c] District Maximum is the maximum value calculated at any station in the South Coast AQMD jurisdiction.
[d] Concentrations are the maximum value observed at any station in the SCAB. Number of daily exceedances are the total number of days that the indicated concentration is exceeded at any station in the SCAB.

Table 3.2-7
South Coast AQMD – 2019 Air Quality Data – PM2.5

SUSPENDED PARTICULATE MATTER PM2.5 [a]						
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. μg/m^3, 24-hour	98[th] Percentile Conc. in μg/m^3 24-hr	No. (%) Samples Exceeding Federal Std > 35 μg/m^3, 24-hour	Annual Average AAM Conc.[b] μg/m^3
LOS ANGELES COUNTY						
1	Central LA	360	43.50	28.3	1 (0.3%)	10.85
2	Northwest Coastal LA County	--	--	--	--	--
3	Southwest Coastal LA County	--	--	--	--	--
4	South Coastal LA County 1	159	28	20.7	0	9.23
4	South Coastal LA County 2	354	30.6	23.20	0	9.22
4	South Coastal LA County 3	--	--	--	--	--
4	I-710 Near Road##	365	36.7	26.4	1 (0.3%)	10.99
6	West San Fernando Valley	118	30	26.3	0	9.16
8	West San Gabriel Valley	118	30.9	24.6	0	8.90
9	East San Gabriel Valley 1	120	28.3	21.2	0	9.18
9	East San Gabriel Valley 2	--	--	--	--	--
10	Pomona/Walnut Valley	--	--	--	--	--
11	South San Gabriel Valley	119	29.6	24.4	0	10.34
12	South Central LA County	303	39.5	26.6	1 (0.3%)	10.87
13	Santa Clarita Valley	--	--	--	--	--
ORANGE COUNTY						
16	North Orange County	--	--	--	--	--
17	Central Orange County	346	36.1	23.3	3 (0.9%)	9.32
17	I-5 Near Road##	--	--	--	--	--
18	North Coastal Orange County	--	--	--	--	--
19	Saddleback Valley	111	20.8	14.7	0	7.11
RIVERSIDE COUNTY						
22	Corona/Norco Area	--	--	--	--	--
23	Metropolitan Riverside County 1	352	46.7	31.8	4 (1.1%)	11.13
23	Metropolitan Riverside County 3	356	46.7	36.2	9 (2.5%)	12.53
24	Perris Valley	--	--	--	--	--
25	Lake Elsinore	--	--	--	--	--
26	Temecula Valley	--	--	--	--	--
29	San Gorgonio Pass	--	--	--	--	--
30	Coachella Valley 1**	119	15.5	12.4	0	6.05
30	Coachella Valley 2**	118	15	13.5	0	7.37
30	Coachella Valley 3**	--	--	--	--	--
SAN BERNARDINO COUNTY						
32	Northwest San Bernardino Valley	--	--	--	--	--
33	I-10 Near Road##	--	--	--	--	--
33	CA-60 Near Road##	364	41.3	30.7	5 (1.4%)	12.7
34	Central San Bernardino Valley 1	114	46.5	29.7	2 (1.8%)	10.84
34	Central San Bernardino Valley 2	97	34.8	33.0	0	10.06
35	East San Bernardino Valley	--	--	--	--	--
37	Central San Bernardino Mountains	--	--	--	--	--
38	East San Bernardino Mountains	46	31	31.0	0	5.94
DISTRICT MAXIMUM			**46.7**	**36.2**	**9**	**12.70**
SOUTH COAST AIR BASIN			**46.7**	**36.2**	**10**	**12.70**

μg/m^3 = micrograms per cubic meter of air
AAM = Annual Arithmetic Mean
-- Pollutant not monitored
*Incomplete Data **Salton Sea Air Basin

Four near-road sites measuring one or more of the pollutants PM2.5, CO, and/or NO2 are operating near the following freeways: I-1, I-10, CA-60, and I-710
+ High PM10 (≥ 155 μg/m^3) data recorded in Coachella Valley (due to high winds) and the Basin (due to Independence Day fireworks) are excluded in accordance with the U.S. EPA Exceptional Event Rule.

[a] PM2.5 statistics listed above are for the FRM data only. FEM PM2.5 continuous monitoring instruments were operated at some of the above locations for real-time alerts and forecasting only.
[b] Both Federal and State standards are annual average (AAM) > 12.0 μg/m^3.
[c] District Maximum is the maximum value calculated at any station in the South Coast AQMD jurisdiction.
[d] Concentrations are the maximum value observed at any station in the SCAB. Number of daily exceedances are the total number of days that the indicated concentration is exceeded at any station in the SCAB.

Lead

Under the federal Clean Air Act, lead is classified as a "criteria pollutant." Lead causes observed adverse health effects at ambient concentrations. Lead is also deemed a carcinogenic toxic air contaminant (TAC) by the Office of Environmental Health Hazard Assessment (OEHHA). Lead in the atmosphere is a mixture of several lead compounds. Leaded gasoline and lead smelters have been the main sources of lead emitted into the air. Due to the phasing out of leaded gasoline, there was a dramatic reduction in atmospheric lead in the Basin over the past three decades. In fact, there were no violations of the lead standards at South Coast AQMD's regular air monitoring stations from 1982 to 2007, due to the removal of lead from gasoline.

Fetuses, infants, and children are more sensitive than others to the adverse effects of lead exposure. Exposure to low levels of lead can adversely affect the development and function of the central nervous system, leading to learning disorders, distractibility, inability to follow simple commands, and lower intelligence quotient. In adults, increased lead levels are associated with increased blood pressure. Lead poisoning can cause anemia, lethargy, seizures, and death. It appears that there are no direct effects of lead on the respiratory system. Lead can be stored in the bone from early-age environmental exposure, and elevated blood lead levels can occur due to breakdown of bone tissue during pregnancy, hyperthyroidism (increased secretion of hormones from the thyroid gland), and osteoporosis (breakdown of bone tissue). Fetuses and breast-fed babies can be exposed to higher levels of lead because of previous environmental lead exposure of their mothers.[16, 17 18]

As summarized in Table 3.2-8, South Coast AQMD monitored lead concentrations at seven monitoring stations in 2019. The SCAB (Los Angeles County area) is currently in nonattainment for lead. This nonattainment designation was due to the operations of specific stationary sources of lead emissions. The MDAB and SSAB are both in attainment for lead. The South Coast AQMD has petitioned U.S. EPA for a redesignation to attainment for the federal lead standard for the Los Angeles County nonattainment area. Stringent South Coast AQMD rules governing lead-producing sources will help to ensure that there are no future violations of the federal standard. At the time of this report, South Coast AQMD has not yet received a response from U.S. EPA regarding the petition. The current lead concentrations in Los Angeles County are below the federal 3-month rolling average standard of 0.15 $\mu g/m^3$. Further, the state 30-day standard of 1.5 $\mu g/m^3$ was not exceeded in any areas under the jurisdiction of the South Coast AQMD in 2019.

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[16] U.S. Environmental Protection Agency. 2020. Criteria Air Pollutants. Accessed December 10, 2020. https://www.epa.gov/criteria-air-pollutants.

[17] South Coast AQMD. 2015. Health Effects of Air Pollution. http://www.aqmd.gov/docs/default-source/publications/brochures/the-health-effects-of-air-pollution-brochure.pdf.

[18] South Coast AQMD. 2005, May. Guidance Document for Addressing Air Quality Issues in General Plans and Local Planning. https://www.aqmd.gov/home/research/guidelines/planning-guidance/guidance-document.

Sulfates

Sulfates are chemical compounds which contain the sulfate ion and are part of the mixture of solid materials which make up PM10. Most of the sulfates in the atmosphere are produced by oxidation of SO2. Oxidation of sulfur dioxide yields sulfur trioxide (SO3), which reacts with water to form sulfuric acid, which then contributes to acid deposition. The reaction of sulfuric acid with basic substances such as ammonia yields sulfates, a component of PM10 and PM2.5.

Most of the health effects associated with fine particles and SO2 at ambient levels are also associated with sulfates. Thus, both mortality and morbidity effects have been observed with an increase in ambient sulfate concentrations. However, efforts to separate the effects of sulfates from the effects of other pollutants have generally not been successful.[19,20,21]

As summarized in Table 3.2-8, South Coast AQMD monitored sulfate at seven monitoring stations in 2019. The state 24-hour sulfate standard of 25 $\mu g/m^3$ was not exceeded in the South Coast Air Basin, which is in attainment for sulfate. The MDAB and SSAB are also in attainment for sulfate. There are no federal sulfate standards.

Vinyl Chloride

Vinyl chloride is a colorless, flammable gas at ambient temperature and pressure. It is also highly toxic and is classified by the American Conference of Governmental Industrial Hygienists (ACGIH) as A1 (confirmed carcinogen in humans) and by the International Agency for Research on Cancer (IARC) as 1 (known to be a human carcinogen).[22] At room temperature, vinyl chloride is a gas with a sickly-sweet odor that is easily condensed. However, it is stored as a liquid. Due to the hazardous nature of vinyl chloride to human health there are no end products that use vinyl chloride in its monomer form. Vinyl chloride is a chemical intermediate, not a final product. It is an important industrial chemical chiefly used to produce polymer polyvinyl chloride (PVC). The process involves vinyl chloride liquid fed to polymerization reactors where it is converted from a monomer to a polymer PVC. The final product of the polymerization process is PVC in either a flake or pellet form. Billions of pounds of PVC are sold on the global market each year. From its flake or pellet form, PVC is sold to companies that heat and mold the PVC into end products such as PVC pipe and bottles.

In the past, vinyl chloride emissions have been associated primarily with sources such as landfills. Risks from exposure to vinyl chloride are considered to be localized impacts rather than regional impacts. Because landfills in the South Coast AQMD are subject to Rule 1150.1 – Control of Gaseous Emissions from Municipal Solid Waste Landfills, which contain stringent requirements for landfill gas collection and control, potential vinyl chloride emissions are expected to be below the level of detection. Therefore, South Coast AQMD does not monitor for vinyl chloride at its monitoring stations.

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19 U.S. Environmental Protection Agency. 2020. Criteria Air Pollutants. Accessed December 10, 2020. https://www.epa.gov/criteria-air-pollutants.

20 South Coast AQMD. 2015. Health Effects of Air Pollution. http://www.aqmd.gov/docs/default-source/publications/brochures/the-health-effects-of-air-pollution-brochure.pdf.

21 South Coast AQMD. 2005, May. Guidance Document for Addressing Air Quality Issues in General Plans and Local Planning. https://www.aqmd.gov/home/research/guidelines/planning-guidance/guidance-document.

22 International Agency for Research on Cancer. Vinyl Chloride Exposure Data. Accessed December 8, 2020.

Table 3.2-8
South Coast AQMD – 2019 Air Quality Data – Lead and Sulfates

Source Receptor Area No.	Location of Air Monitoring Station	LEAD[a] Max. Monthly Average Conc. m) $\mu g/m^3$	LEAD[a] Max. 3-Month Rolling Average m) $\mu g/m^3$	SULFATES[b] No. Days of Data	SULFATES[b] Max. Conc. $\mu g/m^3$, 24-hour
LOS ANGELES COUNTY					
1	Central LA	0.012	0.010	55	5.1
2	Northwest Coastal LA County	--	--	--	--
3	Southwest Coastal LA County	0.004	0.004	--	--
4	South Coastal LA County 1	--	--	--	--
4	South Coastal LA County 2	0.006	0.005	--	--
4	South Coastal LA County 3	--	--	59	5.8
4	I-710 Near Road##	--	--	--	--
6	West San Fernando Valley	--	--	--	--
8	West San Gabriel Valley	--	--	--	--
9	East San Gabriel Valley 1	--	--	61	6.2
9	East San Gabriel Valley 2	--	--	--	--
10	Pomona/Walnut Valley	--	--	--	--
11	South San Gabriel Valley	0.009	0.007	--	--
12	South Central LA County	0.009	0.007	--	--
13	Santa Clarita Valley	--	--	--	--
ORANGE COUNTY					
16	North Orange County	--	--	--	--
17	Central Orange County	--	--	60	5.1
17	I-5 Near Road##	--	--	--	--
18	North Coastal Orange County	--	--	--	--
19	Saddleback Valley	--	--	--	--
RIVERSIDE COUNTY					
22	Corona/Norco Area	--	--	--	--
23	Metropolitan Riverside County 1	0.008	0.007	121	14.6
23	Metropolitan Riverside County 3	--	--	--	--
24	Perris Valley	--	--	--	--
25	Lake Elsinore	--	--	--	--
26	Temecula Valley	--	--	--	--
29	San Gorgonio Pass	--	--	--	--
30	Coachella Valley 1**	--	--	--	--
30	Coachella Valley 2**	--	--	119	3.2
30	Coachella Valley 3**	--	--	--	--
SAN BERNARDINO COUNTY					
32	Northwest San Bernardino Valley	--	--	--	--
33	I-10 Near Road##	--	--	--	--
33	CA-60 Near Road##	--	--	--	--
34	Central San Bernardino Valley 1	--	--	62	5.2
34	Central San Bernardino Valley 2	0.013	0.011	--	--
35	East San Bernardino Valley	--	--	--	--
37	Central San Bernardino Mountains	--	--	--	--
38	East San Bernardino Mountains	--	--	--	--
DISTRICT MAXIMUM		**0.013**	**0.011**		**14.6**
SOUTH COAST AIR BASIN		**0.013**	**0.011**		**14.6**

$\mu g/m^3$= micrograms per cubic meter of air
-- Pollutant not monitored
* Incomplete Data
** Salton Sea Air Basin
Four near-road sites measuring one or more of the pollutants PM2.5, CO, and/or NO2 are operating near the following freeways: I-1, I-10, CA-60, and I-710.

+ High PM10 (≥ 155 $\mu g/m^3$) data recorded in Coachella Valley (due to high winds) and the Basin (due to Independence Day fireworks) are excluded in accordance with the U.S. EPA Exceptional Event Rule.
++ Higher lead concentrations were recorded at near-source monitoring sites immediately downwind of stationary lead sources. Maximum monthly and 3-month rolling averages recorded were 0.88 μ/m^3 and 0.06 μ/m^3.

[a] Federal lead standard is 3-months rolling average > 0.15 $\mu g/m^3$; state standard is monthly average ≥ 1.5 $\mu g/m^3$. Lead standards were not exceeded.
[b] State sulfate standard is 24-hour ≥ 25 $\mu g/m^3$. There is no federal standard for sulfate. Sulfate data is not available at this time.

Volatile Organic Compounds
It should be noted that there are no state or NAAQS for VOCs because they are not classified as criteria pollutants. VOCs are regulated, however, because VOCs are a precursor to the formation of ozone in the atmosphere. VOCs are also transformed into organic aerosols in the atmosphere, contributing to higher PM10 and lower visibility levels.

Although health-based standards have not been established for VOCs, health effects can occur from exposures to high concentrations of VOCs because of interference with oxygen uptake. In general, ambient VOC concentrations in the atmosphere are suspected to cause coughing, sneezing, headaches, weakness, laryngitis, and bronchitis, even at low concentrations. Some hydrocarbon components classified as VOC emissions are thought or known to be hazardous. Benzene, for example, one hydrocarbon component of VOC emissions, is known to be a human carcinogen.

Non-Criteria Pollutants
Although South Coast AQMD's primary mandate is attaining the state and NAAQS for criteria pollutants within the Basin, South Coast AQMD also has a general responsibility pursuant to Health and Safety Code Section 41700 to control emissions of air contaminants and prevent endangerment to public health. Additionally, state law requires South Coast AQMD to implement airborne toxic control measures (ATCM) adopted by CARB and to implement the Air Toxics "Hot Spots" Act. As a result, South Coast AQMD has regulated pollutants other than criteria pollutants such as TACs, GHGs, and stratospheric ozone depleting compounds. South Coast AQMD has developed several rules which are designed to control non-criteria pollutants from both new and existing sources. These rules originated through state directives, CAA requirements, or the South Coast AQMD rulemaking process.

In addition to promulgating non-criteria pollutant rules, South Coast AQMD has been evaluating control measures in the 2016 AQMP as well as existing rules to determine whether they would affect, either positively or negatively, emissions of non-criteria pollutants. For example, rules which target the VOC components of coating materials and that allow for the replacement of the VOC components with a non-photochemically reactive chlorinated substance would reduce the impacts resulting from ozone formation, but could increase emissions of toxic compounds or other substances that may have adverse impacts on human health.

Carcinogenic Health Risks from TACs: One of the primary health risks of concern due to exposure to TACs is the risk of contracting cancer. The carcinogenic potential of TACs is a public health concern because it is currently believed by many scientists that there is no 'safe' level of exposure to carcinogens. Any exposure to a carcinogen poses some risk of causing cancer. It is currently estimated that about one in four deaths in the United States is attributable to cancer. The proportion of cancer deaths attributable to air pollution has not been estimated using epidemiological methods.

Non-cancer Health Risks from TACs: Unlike carcinogens, for most non-carcinogens it is believed that there is a threshold level of exposure to the compound below which it will not pose a health risk. CalEPA's OEHHA develops Reference Exposure Levels (RELs) for TACs are health-conservative estimates of the levels of exposure at or below which health effects are not expected. The non-cancer health risk due to exposure to a TAC is assessed by comparing the estimated level of exposure to the REL. The comparison is expressed as the ratio of the estimated exposure level to the REL, called the hazard index (HI).

Multiple Air Toxics Exposure Study (MATES): In 1986, South Coast AQMD conducted the first MATES report to determine the risks associated with major airborne carcinogens in the SCAB. The most current version (MATES V[23]) consists of a monitoring program, an updated emissions inventory of TACs, and a modeling effort to characterize risk across the SCAB. The study focuses on the carcinogenic risk from exposure to air toxics but does not estimate mortality or other health effects from criteria pollutant exposures which are conducted as part of the 2016 AQMP. Two key updates were implemented in MATES V. First, cancer risk estimations now take into account multiple exposure pathways. Previous MATES studies quantified the cancer risks based on the inhalation pathway only; a cumulative cancer risk accounting for inhalation and non-inhalation pathways is approximately 8% higher than the inhalation-only calculation for the MATES V data. Second, along with cancer risk estimates, MATES V includes information on the chronic non-cancer health impacts from inhalation and non-inhalation pathways for the first time. The cumulative chronic hazard index accounting for the inhalation and non-inhalation pathways is approximately twice the inhalation-only calculation for the MATES V data.

[23] South Coast AQMD, MATES V, Multiple Air Toxics Exposure Study in the South Coast AQMD, Final Report, August 2021. http://www.aqmd.gov/docs/default-source/planning/mates-v/mates-v-final-report.pdf

3.2.2 GREENHOUSE GAS EMISSIONS

Greenhouse gases (GHGs) trap heat in the atmosphere, which in turn heats the surface of the Earth. Some GHGs occur naturally and are emitted to the atmosphere through natural processes, while others are created and emitted solely through human activities. The latter, anthropogenic sources of GHGs, is the focus of impacts under CEQA. Traditionally, GHGs and other global warming pollutants are perceived as solely global in their impacts, and that increasing emissions anywhere in the world contributes to climate change anywhere in the world. A study conducted on the health impacts of CO2 'domes' that form over urban areas showed that they cause increases in local temperatures and local criteria pollutants, which have adverse health effects.[24]

3.2.2.1 Climate Change

Global climate change is a change in the average weather of the Earth, which can be measured by wind patterns, storms, precipitation, and temperature. Historical records have shown that temperature changes have occurred in the past, such as during previous ice ages. Data indicate that the current temperature record differs from previous climate changes in rate and magnitude.

Gases that trap heat in the atmosphere are often called greenhouse gases (GHGs), comparable to a greenhouse, which captures and traps radiant energy. GHGs are emitted by natural processes and human activities. The accumulation of greenhouse gases in the atmosphere regulates the earth's temperature. Global warming is the observed increase in average temperature of the earth's surface and atmosphere. The primary cause of global warming is an increase of GHGs in the atmosphere. The six major GHGs are carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs), and perfluorocarbon (PFCs). The GHGs absorb longwave radiant energy emitted by the Earth, which warms the atmosphere. The GHGs also emit longwave radiation both upward to space and back down toward the surface of the Earth. The downward part of this longwave radiation emitted by the atmosphere is known as the "greenhouse effect." Emissions from human activities such as fossil fuel combustion for electricity production and vehicles have elevated the concentration of these gases in the atmosphere.

- **Carbon dioxide (CO2)** is an odorless, colorless greenhouse gas. Natural sources include the following: decomposition of dead organic matter; respiration of bacteria, plants, animals, and fungus; evaporation from oceans; and volcanic outgassing. Anthropogenic (human caused) sources of CO2 include burning coal, oil, gasoline, natural gas, and wood.
- **Methane (CH4)** is a flammable gas and is the main component of natural gas.
- **Nitrous Oxide (N2O)**, also known as laughing gas, is a colorless greenhouse gas. Some industrial processes such as fossil fuel-fired power plants, nylon production, nitric acid production, and vehicle emissions also contribute to the atmospheric load of N2O.
- **Hydrofluorocarbons (HFCs)** are synthetic man-made chemicals that are used as a substitute for chlorofluorocarbons (whose production was stopped as required by the Montreal Protocol) for automobile air conditioners and refrigerants. The two main sources of perfluorocarbon (PFCs) are primary aluminum production and semiconductor manufacture. Sulfur hexafluoride (SF6) is an inorganic, odorless, colorless, nontoxic,

[24] Jacobsen, Mark Z. "Enhancement of Local Air Pollution by Urban CO_2 Domes," Environmental Science and Technology, as describe in Stanford University press release on March 16, 2010 available at: http://news.stanford.edu/news/2010/march/urban-carbon-domes-031610.html

nonflammable gas. SF6 is used for insulation in electric power transmission and distribution equipment, in the magnesium industry, in semiconductor manufacturing, and as a tracer gas for leak detection.

Scientific consensus, as reflected in recent reports issued by the United Nations Intergovernmental Panel on Climate Change, is that the majority of the observed warming over the last 50 years can be attributable to increased concentration of GHGs in the atmosphere due to human activities. Human activities are directly altering the chemical composition of the atmosphere through the buildup of climate change pollutants. In the past, gradual changes in temperature changed the distribution of species, availability of water, etc. However, human activities are accelerating this process so that environmental impacts associated with climate change no longer occur in a geologic time frame but in a human's lifetime. Industrial activities, particularly increased consumption of fossil fuels (gasoline, diesel, coal, etc.), have heavily contributed to the increase in atmospheric levels of GHGs. The United Nations Intergovernmental Panel on Climate Change constructed several emission trajectories of greenhouse gases needed to stabilize global temperatures and climate change impacts. It concluded that a stabilization of greenhouse gases at 400 to 450 ppm carbon dioxide-equivalent (CO2eq) concentration is required to keep global mean warming below two degrees Celsius, which has been identified as necessary to avoid dangerous impacts from climate change.[25]

The potential health effects from global climate change may arise from temperature increases, climate-sensitive diseases, extreme events, air quality impacts, and sea level rise. There may be direct temperature effects through increases in average temperature leading to more extreme heat waves and less extreme cold spells. Those living in warmer climates are likely to experience more stress and heat-related problems (e.g., heat rash and heat stroke). In addition, climate sensitive diseases may increase, such as those spread by mosquitoes and other insects. Those diseases include malaria, dengue fever, yellow fever, and encephalitis. Extreme events such as flooding, hurricanes, and wildfires can displace people and agriculture, which would have negative consequences. Drought in some areas may increase, which would decrease water and food availability. Global warming may also contribute to air quality problems from increased frequency of smog and particulate air pollution.[26]

The impacts of climate change will also affect projects in various ways. Effects of climate change are rising sea levels and changes in snowpack.[27] The extent of climate change impacts at specific locations remains unclear.

It is expected that federal, state and local agencies will more precisely quantify impacts in various regions. As an example, it is expected that the California Department of Water Resources will formalize a list of foreseeable water quality issues associated with various degrees of climate change. Once state government agencies make these lists available, they could be used to more precisely determine to what extent a project creates global climate change impacts.

[25] Intergovernmental Panel on Climate Change (IPCC). 2014. *Fifth Assessment Report: Climate Change 2014*. New York: Cambridge University Press.

[26] Center for Disease Control. 2016. Climate Change Decreases the Quality of the Air We Breathe. https://www.cdc.gov/climateandhealth/pubs/AIR-QUALITY-Final_508.pdf

[27] Office of Environmental Health Hazards Assessment, 2018. Indicators of Climate Change in California. https://oehha.ca.gov/media/downloads/climate-change/report/2018caindicatorsreportmay2018.pdf, accessed April 3, 2019.

3.2.2.2 Federal

Greenhouse Gas Endangerment Findings: On December 7, 2009, the U.S. EPA Administrator signed two distinct findings regarding greenhouse gases pursuant to the federal Clean Air Act (CAA) Section 202(a). The Endangerment Finding stated that CO2, CH4, N2O, HFCs, PFCs, and SF6 taken in combination endanger both the public health and the public welfare of current and future generations. The *Cause or Contribute Finding* stated that the combined emissions from motor vehicles and motor vehicle engines contribute to the greenhouse gas air pollution that endangers public health and welfare. These findings were a prerequisite for implementing GHG standards for vehicles. The U.S. EPA and the National Highway Traffic Safety Administration (NHTSA) finalized emission standards for light-duty vehicles in May 2010 and for heavy-duty vehicles in August of 2011. Subsequently, the U.S. EPA rolled back the light duty GHG standards, a decision which is currently under litigation. In August 2021, EPA proposed replacement GHG standards for light-duty vehicles and announced plans to reduce GHG emissions from heavy-duty trucks through a series of major rulemakings over the next three years with the first to be finalized in 2022.[28]

Renewable Fuel Standard: The Renewable Fuel Standard (RFS) program was established under the Energy Policy Act (EPAct) of 2005 and required 7.5 billion gallons of renewable-fuel to be blended into gasoline by 2012. Under the Energy Independence and Security Act (EISA) of 2007, the RFS program was expanded to include diesel, required that the volume of renewable fuel blended into transportation fuel be increased from nine billion gallons in 2008 to 36 billion gallons by 2022, established new categories of renewable fuel and required U.S. EPA to apply lifecycle GHG performance threshold standards so that each category of renewable fuel emits fewer greenhouse gases than the petroleum fuel it replaces.

GHG Tailoring Rule: On May 13, 2010, U.S. EPA finalized the GHG Tailoring Rule to phase in the applicability of the Prevention of Significant Deterioration (PSD) and Title V operating permit programs for GHGs. The GHG Tailoring Rule was tailored to include the largest GHG emitters, while excluding smaller sources (restaurants, commercial facilities and small farms). The first phase (from January 2, 2011 to June 30, 2011) addressed the largest sources that contributed 65 percent of the stationary GHG sources. Title V GHG requirements were triggered only when affected facility owners/operators were applying, renewing or revising their permits for non-GHG pollutants. PSD GHG requirements were applicable only if sources were undergoing permitting actions for other non-GHG pollutants and the permitted action would increase GHG emission by 75,000 metric tons of CO2 equivalent emissions (CO2e) per year or more. The Tailoring Rule originally included a second phase for sources that were not otherwise major sources but had the potential to emit 100,000 metric tons of CO2e per year. In 2014, the U.S. Supreme Court held that U.S. EPA was limited to phase 1.

GHG Reporting Program: U.S. EPA issued the Mandatory Reporting of Greenhouse Gases Rule (40 CFR Part 98) under the 2008 Consolidated Appropriations Act. The Mandatory Reporting of Greenhouse Gases Rule requires reporting of GHG data from large sources and suppliers under the Greenhouse Gas Reporting Program (GHGRP). Suppliers of certain products that would result in GHG emissions if released, combusted or oxidized; direct emitting source categories; and facilities that inject CO2 underground for geologic sequestration or any purpose other than

[28] U.S. EPA, EPA to Overhaul Pollution Standards for Passenger Vehicles and Heavy-Duty Trucks, Paving Way for Zero-Emission Future, News Release, August 5, 2021. https://www.epa.gov/newsreleases/epa-overhaul-pollution-standards-passenger-vehicles-and-heavy-duty-trucks-paving-way

geologic sequestration are included. Facilities that emit 25,000 metric tons or more per year of GHGs as CO2e are required to submit annual reports to U.S. EPA.

Ozone-Depleting Substances. Under the CAA Title VI, the U.S. EPA is assigned responsibility for implementing programs that protect the stratospheric ozone layer. 40 CFR Part 82 contains U.S. EPA's regulations specific to protecting the ozone layer. These U.S. EPA regulations phase out the production and import of ozone-depleting substances (ODSs) consistent with the Montreal Protocol.[29] ODSs are typically used as refrigerants or as foam-blowing agents. ODS are regulated as Class I or Class II controlled substances. Class I substances have a higher ozone-depleting potential and have been completely phased out in the United States, except for exemptions allowed under the Montreal Protocol. Class II substances are HCFCs, which are transitional substitutes for many Class I substances and are being phased out.

3.2.2.3 State

3.2.2.3.1 Statewide GHG Reduction Targets

Executive Order S-3-05: In June 2005, Governor Schwarzenegger signed Executive Order S-3-05, which established emission reduction targets. The goals would reduce GHG emissions to 2000 levels by 2010, then to 1990 levels by 2020, and to 80 percent below 1990 levels by 2050.

AB 32 – Global Warming Solutions Act: On September 27, 2006, AB 32, the California Global Warming Solutions Act of 2006, was signed by Governor Schwarzenegger. AB 32 expanded on Executive Order S-3-05. The California legislature stated that "global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California." AB 32 represented the first enforceable statewide program in the U.S. to cap all GHG emissions from major industries that includes penalties for non-compliance. While acknowledging that national and international actions will be necessary to fully address the issue of global warming, AB 32 laid out a program to inventory and reduce GHG emissions in California and from power generation facilities located outside the state that serve California residents and businesses.

Consistent with the requirement to develop an emission reduction plan, CARB prepared a Scoping Plan indicating how GHG emission reductions will be achieved through regulations, market mechanisms, and other actions. The 2008 Scoping Plan called for reducing GHG emissions to 1990 levels by 2020. This means cutting approximately 30 percent from business-as-usual (BAU) emission levels projected for 2020, or about 15 percent from 2005 to 2008 levels.[30] However, as of January 1, 2020, SB 32 became the guiding GHG regulation.

SB 32 and AB 197: In September 2016, Governor Brown signed Senate Bill 32 and Assembly Bill 197, making the Executive Order goal for year 2030 into a statewide, mandated legislative target. AB 197 established a joint legislative committee on climate change policies and requires the CARB to prioritize direct emissions reductions rather than the market-based cap-and-trade program for large stationary, mobile, and other sources. CARB prepared a 2017 Climate Change Scoping Plan Update, which outlines potential regulations and programs, including strategies

[29] The Montreal Protocol on Substances that Deplete the Ozone Layer (Montreal Protocol) is an international treaty designed to phase out halogenated hydrocarbons such as chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs), which are considered ODSs. The Montreal Protocol was first signed on September 16, 1987 and has been revised seven times. The U.S. ratified the original Montreal Protocol and each of its revisions.

[30] California Air Resources Board. 2008, December. Climate Change Scoping Plan, A Framework for Change.

consistent with AB 197 requirements, to achieve the 2030 target. The 2017 Scoping Plan establishes a new emissions limit of 260 $MMTCO_2eq$ for the year 2030, which corresponds to a 40 percent decrease in 1990 levels by 2030.[31]

California's climate strategy will require contributions from all sectors of the economy, including enhanced focus on zero- and near-zero-emission (ZE/NZE) vehicle technologies; continued investment in renewables such as solar roofs, wind, and other types of distributed generation; greater use of low carbon fuels; integrated land conservation and development strategies; coordinated efforts to reduce emissions of short-lived climate pollutants (methane, black carbon, and fluorinated gases); and an increased focus on integrated land use planning to support livable, transit-connected communities and conserve agricultural and other lands. Requirements for GHG reductions at stationary sources complement local air pollution control efforts by the local air districts to tighten criteria air pollutants and TACs emissions limits on a broad spectrum of industrial sources. Major elements of the 2017 Scoping Plan framework include:

- Implementing and/or increasing the stringency of the standards for the various strategies covered under the Mobile Source Strategy, which include increasing ZE buses and trucks.
- Low Carbon Fuel Standard (LCFS), with an increased stringency (18 percent by 2030).
- Implementation of SB 350, which expands the Renewables Portfolio Standard (RPS) to 50 percent RPS and doubles energy efficiency savings by 2030.
- California Sustainable Freight Action Plan, which improves freight system efficiency and utilizes near-zero emissions technology and deployment of ZE trucks.
- Implementing the proposed Short-Lived Climate Pollutant Strategy, which focuses on reducing methane and hydrofluorocarbon emissions by 40 percent and anthropogenic black carbon emissions by 50 percent by year 2030.
- Post-2020 Cap-and-Trade Program that includes declining caps.
- Continued implementation of SB 375.
- Development of a Natural and Working Lands Action Plan to secure California's land base as a net carbon sink.[32]

In addition to the statewide strategies listed above, the 2017 Climate Change Scoping Plan also identified local governments as essential partners in achieving the state's long-term GHG reduction goals and recommended local actions to reduce GHG emissions—for example, statewide targets of no more than 6 $MTCO_2eq$ or less per capita by 2030 and 2 $MTCO_2eq$ or less per capita by 2050. CARB recommends that local governments evaluate and adopt robust and quantitative locally appropriate goals that align with the statewide per capita targets and sustainable development objectives and develop plans to achieve the local goals. The statewide per capita goals were developed by applying the percent reductions necessary to reach the 2030 and 2050 climate goals (i.e., 40 percent and 80 percent, respectively) to the state's 1990 emissions limit established under AB 32. For CEQA projects, CARB states that lead agencies have discretion to

[31] California Air Resources Board, 2017, California's 2017 Climate Change Scoping Plan: The Strategy for Achieving California's 2030 Greenhouse Gas Target, https://www.arb.ca.gov/cc/scopingplan/2030sp_pp_final.pdf, accessed on March 18, 2019.

[32] California Air Resources Board, 2017, California's 2017 Climate Change Scoping Plan: The Strategy for Achieving California's 2030 Greenhouse Gas Target, https://www.arb.ca.gov/cc/scopingplan/2030sp_pp_final.pdf, accessed on March 18, 2019.

develop evidenced-based numeric thresholds (mass emissions, per capita, or per service population) consistent with the Scoping Plan and the state's long-term GHG goals. To the degree a project relies on GHG mitigation measures, CARB recommends that lead agencies prioritize on-site design features that reduce emissions, especially from vehicle miles traveled (VMT), and direct investments in GHG reductions within the project's region that contribute potential air quality, health, and economic co-benefits. Where further project design or regional investments are infeasible or not proven to be effective, CARB recommends mitigating potential GHG impacts through purchasing and retiring carbon credits.[33]

The Scoping Plan scenario is set against what is called the business-as-usual (BAU) yardstick—that is, what would the GHG emissions look like if the State did nothing at all beyond the existing policies that are required and already in place to achieve the 2020 limit. It includes the existing renewables requirements, advanced clean cars, the Low Carbon Fuel Standard (LCFS), and the SB 375 program for more vibrant communities, among others. However, it does not include a range of new policies or measures that have been developed or put into statute over the past two years. The known commitments are expected to result in emissions that are 60 $MMTCO_2eq$ above the target in 2030. If the estimated GHG reductions from the known commitments are not realized due to delays in implementation or technology deployment, the post-2020 Cap-and-Trade Program would deliver the additional GHG reductions in the sectors it covers to ensure the 2030 target is achieved.~~[34]~~

3.2.2.3.2 Mobile Sources

AB 1493 Vehicular Emissions: Prior to the U.S. EPA and NHTSA joint rulemaking, Governor Schwarzenegger signed Assembly Bill AB 1493 (2002). AB 1493 requires that CARB develop and adopt, by January 1, 2005, regulations that achieve "the maximum feasible reduction of greenhouse gases emitted by passenger vehicles and light-duty trucks and other vehicles determined by CARB to be vehicles whose primary use is noncommercial personal transportation in the state." CARB originally approved regulations to reduce GHGs from passenger vehicles in September 2004, with the regulations to take effect in 2009 (see amendments to CCR Title 13 Sections 1900 and 1961 (13 CCR 1900, 1961), and the adoption of CCR Title 13 Section 1961.1 (13 CCR 1961.1)). California's first request to the U.S. EPA to implement GHG standards for passenger vehicles was made in December 2005 and subsequently denied by the U.S. EPA in March 2008. The U.S. EPA then granted California the authority to implement GHG emission reduction standards for new passenger cars, pickup trucks, and sport utility vehicles on June 30, 2009. On April 1, 2010, CARB filed amended regulations for passenger vehicles as part of California's commitment toward the national program to reduce new passenger vehicle GHGs from 2012 through 2016. In 2012, CARB approved the Low-Emission Vehicle (LEV) III regulations which include increasingly stringent emission standards for both criteria pollutants and greenhouse gases for new passenger vehicles of manufacture years 2017 through 2025.[35]

Low Carbon Fuel Standard (LCFS): In the 2008 Scoping Plan, CARB identified the LCFS as one of the nine discrete early action GHG reduction measures. The LCFS is designed to decrease the carbon intensity of California's transportation fuel pool and provide an increasing range of

33 CARB, 2017, California's 2017 Climate Change Scoping Plan: The Strategy for Achieving California's 2030 Greenhouse Gas Target, https://www.arb.ca.gov/cc/scopingplan/2030sp_pp_final.pdf, accessed on March 18, 2019.

~~34 California Public Utilities Commission. 2020. Greenhouse Gas Cap-and-Trade Program. https://www.cpuc.ca.gov/general.aspx?id=5932, accessed on December 8, 2020.~~

35 CARB, Low-Emission Vehicle Greenhouse Gas Program, https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program/lev-program/low-emission-vehicle-greenhouse-gas, accessed on August 23, 2021.

low-carbon and renewable alternatives, which reduce petroleum dependency and achieve air quality benefits. CARB approved the LCFS regulation in 2009 and began implementation on January 1, 2011 and has been amended several times since adoption. In 2018, CARB approved amendments to the regulation, which included strengthening and smoothing the carbon intensity benchmarks through 2030 in-line with California's 2030 GHG emission reduction target enacted through SB 32, adding new crediting opportunities to promote zero emission vehicle adoption, alternative jet fuel, carbon capture and sequestration, and advanced technologies to achieve deep decarbonization in the transportation sector. The LCFS is designed to encourage the use of cleaner low-carbon transportation fuels in California, encourage the production of those fuels, and therefore, reduce GHG emissions and decrease petroleum dependence in the transportation sector. The LCFS standards are expressed in terms of the 'carbon intensity' of gasoline and diesel fuel and their respective substitutes. The program is based on the principle that each fuel has 'lifecycle' greenhouse gas emissions that include CO_2, CH_4, N_2O, and other GHG contributors. This lifecycle assessment examines the GHG emissions associated with the production, transportation, and use of a given fuel. The lifecycle assessment includes direct emissions associated with producing, transporting, and using the fuels, as well as significant indirect effects on GHG emissions, such as changes in land use for some biofuels. The carbon intensity scores assessed for each fuel are compared to a declining carbon intensity benchmark for each year. Low carbon fuels below the benchmark generate credits, while fuels above the carbon intensity benchmark generate deficits. Providers of transportation fuels must demonstrate that the mix of fuels they supply for use in California meets the LCFS carbon intensity standards, or benchmarks, for each annual compliance period. A deficit generator meets its compliance obligation by ensuring that the amount of credits it earns or otherwise acquires from another party is equal to, or greater than, the deficits it has incurred.

EO S-1-07: Governor Schwarzenegger signed Executive Order S-1-07 in 2007 which established the transportation sector as the main source of GHG emissions in California. Executive Order S-1-07 proclaims that the transportation sector accounts for over 40 percent of statewide GHG emissions. Executive Order S-1-07 also establishes a goal to reduce the carbon intensity of transportation fuels sold in California by a minimum of 10 percent by 2020. Executive Order S-1-07 established the LCFS and directed the Secretary for Environmental Protection to coordinate the actions of the CEC, CARB, the University of California, and other agencies to develop and propose protocols for measuring the 'life-cycle carbon intensity' of transportation fuels. The analysis supporting development of the protocols was included in the State Alternative Fuels Plan adopted by CEC on December 24, 2007 and was submitted to CARB for consideration as an 'early action' item under AB 32. CARB adopted the LCFS on April 23, 2009.

EO B-16-2012: On March 23, 2012, the State announced that CARB, the California Energy Commission (CEC), the Public Utilities Commission, and other relevant agencies worked with the Plug-in Electric Vehicle Collaborative and the California Fuel Cell Partnership to establish benchmarks to accommodate ZE vehicles in major metropolitan areas, including infrastructure to support them (e.g., electric vehicle charging stations). The executive order also directed the number of ZE vehicles in California's state vehicle fleet to increase through the normal course of fleet replacement so that at least 10 percent of fleet purchases of light-duty vehicles are ZE by 2015 and at least 25 percent by 2020. The executive order also establishes a target for the transportation sector of reducing GHG emissions 80 percent below 1990 levels.

EO N-79-20: On September 23, 2020 Governor Newsom signed Executive Order N-79-20 which identifies a goal that 100 percent of in-state sales of new passenger cars and trucks will be zero-emission by 2035. Additionally, this Executive Order identified fleet goals for trucks of 100 percent of drayage trucks be zero emissions by 2035 and 100 percent of medium- and heavy-duty vehicles in the State be zero-emission by 2045, for all operations where feasible. Additionally, the Executive Order identifies a goal for the State to transition to 100 percent zero-emission off-road vehicles and equipment by 2035 where feasible.

Senate Bill 44. The California Legislature passed Senate Bill (SB) 44, acknowledging the ongoing need to evaluate opportunities for mobile source emissions reductions and requires CARB to update the 2016 Mobile Source Strategy by January 1, 2021, and every five years thereafter. Specifically, SB 44 requires CARB to update the 2016 Mobile Source Strategy to include a comprehensive strategy for the deployment of medium- and heavy-duty vehicles for meeting air quality standards and reducing GHG emissions. It also directs CARB to set reasonable and achievable goals for reducing emissions by 2030 and 2050 from medium- and heavy-duty vehicles that are consistent with the California's overall goals and maximizes the reduction of criteria air pollutants.

SB 375: SB 375, signed into law in September 2008, aligns regional transportation planning efforts, regional GHG reduction targets, and land use and housing allocation. As part of the alignment, SB 375 requires Metropolitan Planning Organizations (MPOs) to adopt a Sustainable Communities Strategy (SCS) or Alternative Planning Strategy (APS) which prescribes land use allocation in that MPO's Regional Transportation Plan (RTP). CARB, in consultation with MPOs, is required to provide each affected region with reduction targets for GHGs emitted by passenger cars and light trucks in the region for the years 2020 and 2035. These reduction targets will be updated every eight years but can be updated every four years if advancements in emissions technologies affect the reduction strategies to achieve the targets. CARB is also charged with reviewing each MPO's SCS or APS for consistency with its assigned GHG emission reduction targets. If MPOs do not meet the GHG reduction targets, transportation projects located in the MPO boundaries would not be eligible for funding programmed after January 1, 2012.

CARB appointed the Regional Targets Advisory Committee (RTAC), as required under SB 375, on January 23, 2009. The RTAC's charge was to advise CARB on the factors to be considered and methodologies to be used for establishing regional targets. The RTAC provided its recommendation to CARB on September 29, 2009. CARB was required to adopt final targets by September 30, 2010.[36]

CARB is required to update the targets for the MPOs every eight years. CARB adopted revised SB 375 targets for the MPOs in March 2018.[37,38] The updated targets become effective on October 1, 2018. The targets consider the need to further reduce VMT, as identified in the 2017 Scoping Plan Update (for SB 32), while balancing the need for additional and more flexible revenue sources to incentivize positive planning and action toward sustainable communities. Like the 2010 targets, the updated SB 375 targets are in units of percent per capita reduction in GHG emissions from automobiles and light trucks relative to 2005; this excludes reductions anticipated from implementation of state technology and fuels strategies, and any potential future state strategies, such as statewide road user pricing. The proposed targets call for greater per-capita GHG emission

[36] California Air Resources Board 2010, August. Staff Report Proposed Regional Greenhouse Gas Emission Reduction Targets for Automobiles and Light Trucks Pursuant to Senate Bill 375.

[37] California Air Resources Board, 2018, SB 375 Regional Greenhouse Gas Emissions Reduction Targets https://ww2.arb.ca.gov/sites/default/files/2020-06/SB375_Final_Targets_2018.pdf, accessed on December 8, 2020.

[38] California Air Resources Board, 2018, Updated Final Staff Report: Proposed Update to the SB 375 Greenhouse Gas Emissions Reduction Targets.

reductions from SB 375 than are currently in place, which for 2035 translate into proposed targets that either match or exceed the emission reduction levels in the MPOs' currently adopted SCS to achieve the SB 375 targets. For the next round of SCS updates, CARB's updated targets for the SCAG region are an 8 percent per capita GHG reduction in 2020 from 2005 levels (unchanged from the 2010 target) and a 19 percent per capita GHG reduction in 2035 from 2005 levels (compared to the 2010 target of 13 percent).[39] CARB adopted the updated targets and methodology on March 22, 2018. All SCSs adopted after October 1, 2018, are subject to these new targets.

SCAG's Regional Transportation Plan / Sustainable Communities Strategy: SB 375 requires each MPO to prepare a sustainable communities strategy in its regional transportation plan. SCAG released the draft 2020-2045 RTP/SCS (Connect SoCal) on November 7, 2019. On September 3, 2020, SCAG's Regional Council unanimously voted to approve and fully adopt the Connect SoCal Plan.[40] In general, the SCS outlines a development pattern for the region that, when integrated with the transportation network and other transportation measures and policies, would reduce vehicle miles traveled from automobiles and light duty trucks and thereby reduce GHG emissions from these sources.

Connect SoCal focuses on the continued efforts of the previous RTP/SCSs to integrate transportation and land uses strategies in development of the SCAG region through horizon year 2045. Connect SoCal forecasts that the SCAG region will meet its GHG per capita reduction targets of 8 percent by 2020 and 19 percent by 2035. Additionally, Connect SoCal also forecasts that implementation of the plan will reduce VMT per capita in year 2045 by 4.1 percent compared to baseline conditions for that year. Connect SoCal includes a 'Core Vision' that centers on maintaining and better managing the transportation network for moving people and goods while expanding mobility choices by locating housing, jobs, and transit closer together, and increasing investments in transit and complete streets.

3.2.2.3.3 Adaptation

EO S-13-08: Governor Schwarzenegger signed Executive Order S-13-08 on November 14, 2008 which directed California to develop methods for adapting to climate change through preparation of a statewide plan. Executive Order S-13-08 directed OPR, in cooperation with the Resources Agency, to provide land use planning guidance related to sea level rise and other climate change impacts by May 30, 2009. Executive Order S-13-08 also directed the Resources Agency to develop a state Climate Adaptation Strategy by June 30, 2009 and to convene an independent panel to complete the first California Sea Level Rise Assessment Report. The assessment report was required to be completed by December 1, 2010 and required to meet the following four criteria:

1. Project the relative sea level rise specific to California by considering issues such as coastal erosion rates, tidal impacts, El Niño and La Niña events, storm surge, and land subsidence rates;
2. Identify the range of uncertainty in selected sea level rise projections;
3. Synthesize existing information on projected sea level rise impacts to state infrastructure (e.g., roads, public facilities, beaches), natural areas, and coastal and marine ecosystems; and

[39] California Air Resources Board. 2018, February. Proposed Update to the SB 375 Greenhouse Gas Emission Reduction Targets. https://www.arb.ca.gov/cc/sb375/sb375_target_update_final_staff_report_feb2018.pdf.
[40] Southern California Association of Governments (SCAG). 2020, September. Adopted Final Connect SoCal. https://scag.ca.gov/read-plan-adopted-final-plan, accessed December 8, 2020.

4. Discuss future research needs relating to sea level rise in California.

3.2.2.3.4 Energy

SB 1078, SB 107 and EO S-14-08: SB 1078 (Chapter 516, Statutes of 2002) requires retail sellers of electricity, including investor owned utilities and community choice aggregators, to provide at least 20 percent of their supply from renewable sources by 2017. SB 107 (Chapter 464, Statutes of 2006) changed the target date to 2010. In November 2008, Governor Schwarzenegger signed Executive Order S-14-08, which expands the state's Renewable Portfolio Standard to 33 percent renewable power by 2020.

SB X-1-2: SB X1-2 was signed by Governor Brown in April 2011. SB X1-2 created a new Renewables Portfolio Standard (RPS), which pre-empted CARB's 33 percent Renewable Electricity Standard. The new RPS applies to all electricity retailers in the state including publicly owned utilities (POUs), investor-owned utilities, electricity service providers, and community choice aggregators. These entities must adopt the new RPS goals of 20 percent of retails sales from renewables by the end of 2013, 25 percent by the end of 2016, and the 33 percent requirement by the end of 2020.

SB 1368: SB 1368 is the companion bill of AB 32 and was signed by Governor Schwarzenegger in September 2006. SB 1368 required the CPUC to establish a GHG emission performance standard for baseload generation from investor owned utilities (IOUs) by February 1, 2007. The California Energy Commission (CEC) was also required to establish a similar standard for local publicly owned utilities by June 30, 2007. These standards cannot exceed the greenhouse gas emission rate from a baseload combined-cycle natural gas fired power plant. The legislation further required that all electricity provided to California, including imported electricity, must be generated from power plants that meet the standards set by the Public Utilities Commission (PUC) and CEC.

SB 350: Senate Bill 350 (de Leon) was signed into law September 2015 and establishes tiered increases to the RPS—40 percent by 2024, 45 percent by 2027, and 50 percent by 2030. SB 350 also set a new goal to double the energy-efficiency savings in electricity and natural gas through energy efficiency and conservation measures.

SB 100: On September 10, 2018, Governor Brown signed SB 100. Under SB 100, the RPS for public-owned facilities and retail sellers consist of 44 percent renewable energy by 2024, 52 percent by 2027, and 60 percent by 2030. Additionally, SB 100 also established a new RPS requirement of 50 percent by 2026. Furthermore, the bill establishes an overall state policy that eligible renewable energy resources and zero-carbon resources supply 100 percent of all retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. Under the bill, the state cannot increase carbon emissions elsewhere in the western grid or allow resource shuffling to achieve the 100 percent carbon-free electricity target.

EO B-55-18: Executive Order B-55-18, signed September 10, 2018, sets a goal "to achieve carbon neutrality as soon as possible, and no later than 2045, and achieve and maintain net negative emissions thereafter." Executive Order B-55-18 directs CARB to work with relevant state agencies to ensure future Scoping Plans identify and recommend measures to achieve the carbon neutrality goal. The goal of carbon neutrality by 2045 is in addition to other statewide goals, meaning not only should emissions be reduced to 80 percent below 1990 levels by 2050, but that, by no later than 2045, the remaining emissions be offset by equivalent net removals of CO_2eq from the atmosphere, including through sequestration in forests, soils, and other natural landscapes.

AB 2127: This bill requires the California Energy Commission (CEC), working with CARB and the California Public Utilities Commission (CPUC), to prepare and biennially update a statewide assessment of the electric vehicle charging infrastructure needed to support the levels of electric vehicle adoption required for the state to meet its goals of putting at least 5 million zero-emission vehicles on California roads by 2030 and of reducing emissions of greenhouse gases to 40 percent below 1990 levels by 2030. The bill requires the CEC to regularly seek data and input from stakeholders relating to electric vehicle charging infrastructure.[41]

California Building Code – Building Energy Efficiency Standards: Energy conservation standards for new residential and non-residential buildings were adopted by the California Energy Resources Conservation and Development Commission (now the CEC) in June 1977 (Title 24, Part 6, of the California Code of Regulations [CCR]). Title 24 requires the design of building shells and building components to conserve energy. The standards are updated periodically to allow for consideration and possible incorporation of new energy efficiency technologies and methods. The 2019 Building Energy Efficiency Standards were adopted on May 9, 2018 and went into effect on January 1, 2020. The 2019 standards move toward cutting energy use in new homes by more than 50 percent and will require installation of solar photovoltaic systems for single-family homes and multifamily buildings of three stories and less. The 2019 standards focus on four key areas: 1) smart residential photovoltaic systems; 2) updated thermal envelope standards (preventing heat transfer from the interior to exterior and vice versa); 3) residential and nonresidential ventilation requirements; 4) and nonresidential lighting requirements.[42]

California Building Code – CALGreen: On July 17, 2008, the California Building Standards Commission adopted the nation's first green building standards. The California Green Building Standards Code (24 CCR Part 11, known as 'CALGreen') was adopted as part of the California Building Standards Code. CALGreen established planning and design standards for sustainable site development, energy efficiency (in excess of the California Energy Code requirements), water conservation, material conservation, and internal air contaminants.[43] The mandatory provisions of the California Green Building Code Standards became effective January 1, 2011 and were last updated in 2019. The 2019 CALGreen standards became effective January 1, 2020. Section 5.408 of CALGreen also requires that at least 65 percent of the nonhazardous construction and demolition waste from nonresidential construction operations be recycled and/or salvaged for reuse.

3.2.2.3.5 Short-Lived Climate Pollutants

SB 1383: On September 19, 2016, the Governor signed SB 1383 to supplement the GHG reduction strategies in the Scoping Plan to consider short-lived climate pollutants, including black carbon and methane. Black carbon is the light-absorbing component of fine particulate matter produced during incomplete combustion of fuels. SB 1383 required CARB, no later than January 1, 2018,

[41] California Legislative Information, September 14, 2018, AB-2127 Electric Vehicle Charging Infrastructure: Assessment, https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180AB2127, accessed December 17, 2020.

[42] California Energy Commission (CEC). 2018. News Release: Energy Commission Adopts Standards Requiring Solar Systems for New Homes, First in Nation. http://www.energy.ca.gov/releases/2018_releases/2018-05-09_building_standards_adopted_nr.html. Accessed December 8, 2020.

[43] The green building standards became mandatory in the 2010 edition of the code.

to approve and begin implementing a comprehensive strategy to reduce emissions of short-lived climate pollutants to achieve a reduction in methane by 40 percent, hydrofluorocarbon gases by 40 percent, and anthropogenic black carbon by 50 percent below 2013 levels by 2030, as specified. On March 14, 2017, CARB adopted the "Final Proposed Short-Lived Climate Pollutant Reduction Strategy," which identifies the state's approach to reducing anthropogenic and biogenic sources of short-lived climate pollutants. Anthropogenic sources of black carbon include on- and off-road transportation, residential wood burning, fuel combustion (charbroiling), and industrial processes. According to CARB, ambient levels of black carbon in California are 90 percent lower than in the early 1960s despite the tripling of diesel fuel use. In-use on-road rules are expected to reduce black carbon emissions from on-road sources by 80 percent between 2000 and 2020.

3.2.2.3.6 Ozone Depleting Substances (ODSs)

Refrigerant Management Program: As part of implementing AB 32, CARB also adopted a Refrigerant Management Program in 2009. The Refrigerant Management Program is designed to reduce GHG emissions from stationary sources through refrigerant leak detection and monitoring, leak repair, system retirement and retrofitting, reporting and recordkeeping, and proper refrigerant cylinder use, sale, and disposal.

HFC Emission Reduction Measures for Mobile Air Conditioning – Regulation for Small Containers of Automotive Refrigerant: The Regulation for Small Containers of Automotive Refrigerant applies to the sale, use, and disposal of small containers of automotive refrigerant with a GWP greater than 150. Emission reductions are achieved through implementation of four requirements: 1) use of a self-sealing valve on the container, 2) improved labeling instructions, 3) a deposit and recycling program for small containers, and 4) an education program that emphasizes best practices for vehicle recharging. This regulation went into effect on January 1, 2010 with a one-year sell-through period for containers manufactured before January 1, 2010. The target recycle rate is initially set at 90 percent and rose to 95 percent beginning January 1, 2012.

3.2.2.4 South Coast AQMD

The South Coast AQMD adopted a "Policy on Global Warming and Stratospheric Ozone Depletion" on April 6, 1990. The policy commits the South Coast AQMD to consider global impacts in rulemaking and in drafting revisions to the AQMP. In March 1992, the South Coast AQMD Governing Board reaffirmed this policy and adopted amendments to the policy to include support of the adoption of a California GHG emission reduction goal.

Basin GHG Policy and Inventory: The South Coast AQMD has established a policy, adopted by the South Coast AQMD Governing Board at its September 5, 2008 meeting, to actively seek opportunities to reduce emissions of criteria, toxic, and climate change pollutants. The policy includes the intent to assist businesses and local governments implementing climate change measures, decrease the agency's carbon footprint, and provide climate change information to the public.

3.2.2.4.1 Ozone Depleting Substances (ODSs)

Policy on Global Warming and Stratospheric Ozone Depletion. The South Coast AQMD adopted a "Policy on Global Warming and Stratospheric Ozone Depletion" on April 6, 1990. The policy targeted a transition away from CFCs as an industrial refrigerant and propellant in aerosol cans. In March 1992, the South Coast AQMD Governing Board reaffirmed this policy and adopted amendments to the policy to include the following directives for ODSs:

- Phase out the use and corresponding emissions of CFCs, methyl chloroform (1,1,1-trichloroethane or TCA), carbon tetrachloride, and halons by December 1995.
- Phase out the large quantity use and corresponding emissions of HCFCs by the year 2000.
- Develop recycling regulations for HCFCs.
- Develop an emissions inventory and control strategy for methyl bromide.

SUBCHAPTER 3.3

HAZARDS AND HAZARDOUS MATERIALS

Hazardous Materials Regulations

Emergency Response to Hazardous Materials and Waste Incidents

Hazardous Materials Incidents

Hazards Associated with Air Pollution Control and Refinery Processes

3.3 HAZARDS AND HAZARDOUS MATERIALS

The potential for hazards exists in the production, use, storage, and transportation of hazardous materials. Also, hazard concerns are related to the potential for fires, explosions, or the release of hazardous materials/substances in the event of an accident or upset conditions. Hazardous materials may be found at subject refineries and associated chemical facilities. Some facilities produce hazardous materials as a final product, while others use such materials as feedstock to their production process. Examples of hazardous materials which are manufactured at refineries to be used by consumers include petroleum-based products such as vehicle fuels, flammable gases, and lubricating oils. Hazardous materials are stored at facilities that produce such materials, and at facilities where hazardous materials are a part of the production process. Specifically, storage refers to the bulk handling of hazardous materials before and after they are transported to the general geographical area of use. Currently, hazardous materials are transported to the South Coast AQMD jurisdiction via all modes of transportation including by rail, ship, roadways, air, and pipelines.

Of the 16 facilities from the refinery-sector that are subject to the proposed project, nine facilities were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Eleven facilities from the non-refinery sector were also analyzed. The analysis specifically identified the type of NOx control devices that would be employed, and the environmental impacts associated with the affected facilities undergoing physical modifications to install new or modify existing air pollution control equipment. Compared to the proposed project, the previous analysis in the December 2015 Final PEA for NOx RECLAIM for the nine refinery-sector was based on employing greater numbers of air pollution control equipment with more overall environmental impacts (e.g., more scrubbers and new SCRs) than what would be expected to be installed under the current BARCT proposal (e.g., fewer scrubbers, fewer new SCRs but more existing SCRs being upgraded, and existing burners being replaced with ULNBs). Since the previous analysis in the December 2015 Final PEA for NOx RECLAIM may have overestimated potential impacts for some combustion equipment categories, updates to the previous environmental analysis for these nine facilities are needed.

While seven refinery-sector facilities did not have detailed environmental impacts analyzed in the December 2015 Final PEA for NOx RECLAIM, the currently proposed BARCT NOx emissions levels for these facilities' combustion equipment can be achieved by the same types of air pollution control equipment that were analyzed in the December 2015 Final PEA for NOx RECLAIM. Some updates to the previous environmental analysis are needed to incorporate analyses for these seven additional facilities. As such, this SEA analyzes the incremental changes that may occur if proposed project is implemented, relative to the baseline which was the previous project analyzed in the December 2015 Final PEA for NOx RECLAIM.

Relative to the discussion in the December 2015 Final PEA for NOx RECLAIM for the topic of hazards and hazardous materials, in order to operate the various NOx control technologies for each equipment/source category that were previously analyzed, the following substances would be needed: ammonia, catalyst (such as vanadium pentoxide), caustic made from sodium hydroxide or soda ash, hydrated lime (also known as calcium hydroxide), and oxygen. Of the substances listed in Table 3.3-1 only ammonia was concluded in the December 2015 Final PEA for NOx RECLAIM to have potentially significant adverse hazards and hazardous materials impacts. Ammonia is needed to operate SCR and UltraCat™ with DGS technologies.

Table 3.3-1
Substances Used by NOx Control Technologies Evaluated in the December 2015 Final PEA for NOx RECLAIM

Sector	NOx RECLAIM Equipment/Source Category	Potential NOx Control Devices	Proposed Substances To Be Used/Increased for NOx Control
Refinery	Boilers	SCRs	Ammonia and fresh catalyst
Refinery	Refinery Gas Turbines	SCRs	Ammonia and fresh catalyst
Refinery	FCCUs	1. SCRs 2. LoTOx™ with WGSs 3. LoTOx™ without WGS	1. Ammonia and fresh catalyst 2. Sodium hydroxide 3. Oxygen
Refinery	Petroleum Coke Calciner	1. LoTOx™ with WGS 2. UltraCat™ with DGS	1. Sodium hydroxide 2. Ammonia and hydrated lime
Refinery	Process Heaters	SCRs	Ammonia and fresh catalyst
Refinery	SRU/TGUs	1. LoTOx™ with WGSs 2. SCRs	1. Soda Ash 2. Ammonia and fresh catalyst
Non-Refinery	Container Glass Melting Furnaces	1. SCR 2. UltraCat™ with DGS	1. Ammonia and fresh catalyst 2. Ammonia and hydrated lime
Non-Refinery	Sodium Silicate Furnaces	1. SCR 2. UltraCat™ with DGS	1. Ammonia and fresh catalyst 2. Ammonia and hydrated lime
Non-Refinery	Metal Heat Treating Furnaces	SCRs	Ammonia and fresh catalyst
Non-Refinery	ICEs (Non-Refinery/Non-Power Plant)	SCRs	Ammonia and fresh catalyst
Non-Refinery	Turbines (Non-Refinery/Non-Power Plant)	SCRs	Ammonia and fresh catalyst

Source: Table 4.4-2 of the December 2015 Final PEA for NOx RECLAIM

The following combustion equipment categories will be applicable to refinery-sector facilities subject to PR 1109.1: 1) boilers; 2) gas turbines; 3) ground level flares; 4) fluidized catalytic cracking units; 5) petroleum coke calciners; 6) process heaters; 7) sulfur recover units/tail gas treating units; 8) SMR heaters; 9) SMR heaters with gas turbine; 10) sulfuric acid furnaces; and 11) vapor incinerators. Table 3.3-2 presents a summary of the substances that may be used for each of the potential NOx control technologies per equipment or source category as evaluated in the December 2015 Final PEA for NOx RECLAIM subject to PR 1109.1.

Table 3.3-2
Substances Used by NOx Control Technologies for PR 1109.1

PR 1109.1 Equipment/Source Category	NOx Control Devices	Proposed Substances To Be Used/Increased for NOx Control
Boilers	1. SCR (new or upgrade existing); 2. Replace existing burners with ULNBs; or 3. Combination of the above	1. Ammonia and fresh catalyst for new SCRs and fresh catalyst for upgraded SCRs. 2. None 3. Ammonia and fresh catalyst for new SCRs and fresh catalyst for upgraded SCRs
Gas Turbines	SCR (new or upgrade existing)	Ammonia and fresh catalyst for new SCRs and fresh catalyst for upgraded SCRs
Ground Level Flares	No additional control, but for units that exceed 20 hours per year, replacement with low-NOx flare	None
Fluid Catalytic Cracking Units (FCCUs)	1. SCR (new); 2. LoTOx™ with WGS; or 3. LoTOx™ without WGS	1. Ammonia and fresh catalyst 2. Sodium hydroxide 3. Oxygen
Petroleum Coke Calciner	1. SCR (new;) 2. LoTOx™ with WGS; or 3. UltraCat™ with DGS	1. Ammonia and fresh catalyst 2. Sodium hydroxide 3. Ammonia
Process Heaters	1. SCR (new or upgrade existing); 2. Replace existing burners with ULNBs; or 3. Combination of the above	1. Ammonia and fresh catalyst for new SCRs and fresh catalyst for upgraded SCRs. 2. None 3. Ammonia and fresh catalyst for new SCRs and fresh catalyst for upgraded SCRs
Sulfur Recovery Unit / Tail Gas Units (SRU/TGUs)	Replace existing burners with ULNBs (some currently achieve BARCT limit)	None
SMR Heaters (with/without gas turbine)	1. SCR (new or upgrade existing); 2. Replace existing burners with ULNBs; or 3. Combination of the above	1. Ammonia and fresh catalyst for new SCRs and fresh catalyst for upgraded SCRs. 2. None 3. Ammonia and fresh catalyst for new SCRs and fresh catalyst for upgraded SCRs
Sulfuric Acid Furnaces	None, these units currently achieve BARCT limit	None
Vapor Incinerators	Replace existing burners with ULNBs	None

The key differences between the proposed project and the project evaluated in the December 2015 Final PEA for NOx RECLAIM, is that the proposed project includes NOx BARCT limits for the following additional equipment/source categories: ground level flares, SMR Heaters (with and without a gas turbine), sulfuric acid furnaces, and vapor incinerators. While the proposed project contemplates the same types of NOx control devices as previously evaluated in the December 2015

Final PEA for NOx RECLAIM and the same substances will need to be used for each type of NOx control device for boilers, process heaters, SRU/TGUs, SMR heaters, vapor incinerators, NOx BARCT levels may also be achieved by replacing existing burners with ULNBs, which do not require any substances for their operation. For this reason, the analysis of the proposed project in this SEA also includes the replacement of burners with ULNBs.

Table 3.3-3 lists the incremental number of NOx control devices that may be installed in order to implement PR 1109.1, but that were not previously analyzed in the December 2015 Final PEA for NOx RECLAIM.

Table 3.3-3
Estimated Number of NOx Air Pollution Control Devices Per Equipment Category for 16 Refineries Subject to PR 1109.1 Not Previously Analyzed Under NOx RECLAIM

Equipment Category	Number of Affected Facilities	Estimated Number of Air Pollution Control Devices Not Previously Analyzed in the December 2015 Final PEA for NOx RECLAIM
Refinery Process Heaters and Boilers	9	~~59~~ 47 Burner Replacements with ULNBs ~~20~~ 25 New SCRs ~~6~~ 3 SCR Upgrades 9 Heater/Boiler Replacements
SRU/TGs	4	5 Burner Replacements with ULNBs
Thermal Oxidizers	4	8 Burner Replacements with ULNBs
Refinery Gas Turbines	1	1 SCR Upgrade
	TOTAL	**~~20~~ 25 New SCRs** **~~7~~ 4 SCR Upgrades** **~~72~~ 60 Burner Replacements with ULNBs** **9 Heater/Boiler Replacements**

As with the previous analysis in the December 2015 Final PEA for NOx RECLAIM which concluded potentially significant adverse hazards and hazardous materials impacts due to ammonia, facilities affected by the currently proposed project are anticipated to make physical modifications by installing new or modifying existing air pollution control equipment in order to achieve the proposed BARCT NOx concentration limits in PR 1109.1, with the majority of the modifications relying on SCR technology utilizing ammonia.

3.3.1 Hazardous Materials Regulations

Incidents of harm to human health and the environment associated with hazardous materials have created a public awareness of the potential for adverse effects from accidents and/or use of these substances. As a result, the manufacture, use, storage, and transport of hazardous materials are subject to numerous laws and regulations at all levels of government. The most relevant existing hazardous materials laws and regulations include hazardous materials management planning, hazardous materials transportation, hazardous materials worker safety requirements, hazardous waste handling requirements, and emergency response to hazardous materials and waste incidents. Potential risk of upset is a factor in the production, use, storage, and transportation of hazardous materials. Risk of upset concerns are related to the risks of explosions or the release of hazardous substances in the event of an accident or upset. The most relevant hazardous materials laws and regulations are summarized in the following subsection of this section.

3.3.1.1 Definitions

A number of properties may cause a substance to be hazardous, including toxicity, ignitability, corrosivity, and reactivity. The term "hazardous material" is defined in different ways for different regulatory programs. For the purposes of this document, the term hazardous material refers to and encompasses both hazardous materials and hazardous wastes. A hazardous material is defined as hazardous if it appears on a list of hazardous materials prepared by a federal, state, or local regulatory agency, or if it has characteristics defined as hazardous by such an agency. Hazardous material is defined in Health and Safety Code (HSC) Section 25501~~(k)~~ as follows:

> Hazardous material means any material that because of its quantity, concentrations, or physical or chemical characteristics, poses a significant present or potential hazard to human health and safety or to the environment if released into the workplace or the environment. Hazardous materials include but are not limited to hazardous substances, hazardous waste, and any material which a handler or the administering agency has a reasonable basis for believing would be injurious to the health and safety of persons or harmful to the environment if released into the workplace or the environment.

Examples of the types of materials and wastes considered hazardous are hazardous chemicals (e.g., toxic, ignitable, corrosive, and reactive materials), and some radioactive materials. The characteristics of toxicity, ignitability, corrosivity, and reactivity are defined in California Code of Regulations (CCR), Title 22 Section 66261.20 – 66261.24 and are summarized below:

> **Toxic Substances:** Toxic substances may cause short-term or long-lasting health effects, ranging from temporary effects to permanent disability, or even death. For example, such substances can cause disorientation, acute allergic reactions, asphyxiation, skin irritation, or other adverse health effects if human exposure exceeds certain levels. The levels depend on the substances involved and are chemical-specific. Carcinogens, substances that can cause cancer, are a special class of toxic substances. Examples of toxic substances include benzene which is a component of gasoline and

a known carcinogen, and methylene chloride which is a common laboratory solvent and a potential carcinogen.

Ignitable Substances: Ignitable substances are hazardous because of their ability to burn. Gasoline, hexane, and natural gas are examples of ignitable substances.

Corrosive Materials: Corrosive materials can cause severe burns. Corrosives include strong acids and bases such as sodium hydroxide (lye) or sulfuric acid (battery acid).

Reactive Materials: Reactive materials may cause explosions or generate toxic gases. Explosives, pure sodium or potassium metals (which react violently with water), and cyanides are examples of reactive materials.

3.3.1.2 Federal Regulations

The U.S. EPA is the primary federal agency charged with protecting human health and with safeguarding the natural environment over air, water, and land. The U.S. EPA works to develop and enforce regulations that implement environmental laws enacted by Congress. The U.S. EPA is responsible for researching and setting national standards for a variety of environmental programs, and delegates to states and Native American tribes the responsibility for issuing permits and for monitoring and enforcing compliance. Since 1970, Congress has enacted numerous environmental laws that pertain to hazardous materials, for the U.S. EPA to implement as well as for other agencies to implement at the federal, state, and local level, as described in the following subsections.

Toxic Substances Control Act

The Toxic Substances Control Act (TSCA) was enacted by Congress in 1976 (see 15 U.S.C. Section 2601 et seq.) and gave the U.S. EPA the authority to protect the public from unreasonable risk of injury to health or the environment by regulating the manufacture, sale, and use of chemicals currently produced or imported into the United States. The TSCA, however, does not address wastes produced as byproducts of manufacturing. The types of chemicals regulated by the act fall into two categories: existing and new. New chemicals are defined as "any chemical substance which is not included in the chemical substance list compiled and published under [TSCA] section 8(b)." This list included all chemical substances manufactured or imported into the U.S. prior to December 1979. Existing chemicals include any chemical currently listed under section 8(b). The distinction between existing and new chemicals is necessary as the act regulates each category of chemicals in different ways. The U.S. EPA repeatedly screens both new and existing chemicals and can require reporting or testing of those that may pose an environmental or human-health hazard. The U.S. EPA can ban the manufacture and import of those chemicals that pose an unreasonable risk.

Emergency Planning and Community Right-to-Know Act

The Emergency Planning and Community Right-to-Know Act (EPCRA) is a federal law adopted by Congress in 1986 that is designed to help communities plan for emergencies involving hazardous substances. EPCRA establishes requirements for federal, state and local governments, Indian tribes, and industry regarding emergency planning and "Community Right-to-Know" reporting on hazardous and toxic chemicals. The Community Right-to-Know provisions help increase the public's knowledge of and access to information on chemicals at individual facilities, their uses, and releases into the environment. States and communities, working with facilities, can use the information to improve chemical safety and protect public health and the environment. There are four major provisions of EPCRA:

1. Emergency Planning (Sections 301 – 303) requires local governments to prepare chemical emergency response plans, and to review plans at least annually. These sections also require state governments to oversee and coordinate local planning efforts. Facilities that maintain Extremely Hazardous Substances (EHS) on-site (see 40 CFR Part 355 for the list of EHS chemicals) in quantities greater than corresponding “Threshold Planning Quantities” must cooperate in the preparation of the emergency plan.

2. Emergency Release Notification (Section 304) requires facilities to immediately report accidental releases of EHS chemicals and hazardous substances in quantities greater than corresponding Reportable Quantities (RQs) as defined under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) to federal, state and local officials. Information about accidental chemical releases must be made available to the public.

3. Hazardous Chemical Storage Reporting (Sections 311 – 312) requires facilities that manufacture, process, or store designated hazardous chemicals to make Safety Data Sheets (SDSs) describing the properties and health effects of these chemicals available to state and local officials and local fire departments. These sections also require facilities to report to state and local officials and local fire departments, inventories of all on-site chemicals for which SDSs exist. Lastly, information about chemical inventories at facilities and SDSs must be available to the public.

4. Toxic Chemical Release Inventory (Section 313) requires facilities to annually complete and submit a Toxic Chemical Release Inventory Form for each Toxic Release Inventory (TRI) chemical that is manufactured or otherwise used above the applicable threshold quantities.

Implementation of EPCRA has been delegated to the State of California. The California Office of Emergency Services requires a Hazardous Materials Business Plan to be developed by any facility that manufactures, processes, or stores hazardous materials in quantities equal to or greater than 55 gallons, 500 pounds, or 200 cubic feet of gas or extremely hazardous substances above the threshold planning quantity. The Hazardous Materials Business Plan is required to be provided to State and local emergency response agencies and includes inventories of hazardous materials, an emergency plan, and an implementation training program for employees.

Hazardous Materials Transportation Act

The Hazardous Material Transportation Act (HMTA), adopted in 1975 (see 49 U.S.C. Sections 5101 – 5127), provided the Secretary of Transportation the regulatory and enforcement authority to provide adequate protection against the risks to life and property inherent in the transportation of hazardous material in commerce. The United States Department of Transportation (U.S. DOT) oversees the movement of hazardous materials at the federal level (see 49 CFR Parts 171 – 180). The HMTA requires carriers to report accidental releases of hazardous materials to the U.S. DOT at the earliest practical moment. Other types of incidents that must be reported include deaths, injuries requiring hospitalization, and property damage exceeding $50,000. The hazardous material regulations also contain emergency response provisions which include incident reporting requirements. Reports of major incidents are directed to the National Response Center, which in turn is linked with CHEMTREC, a public service hotline established by the chemical manufacturing industry for emergency responders to obtain information and assistance for emergency incidents involving chemicals and hazardous materials.

Hazardous materials regulations are implemented by the Research and Special Programs Administration (RSPA) branch of the U.S. DOT. The regulations cover the definition and classification of hazardous materials, communication of hazards to workers and the public, packaging and labeling requirements, operational rules for shippers, and training. These regulations apply to interstate, intrastate, and foreign commerce by air, rail, ships, and motor vehicles, and apply to the transportation of hazardous waste. The Federal Aviation Administration Office of Hazardous Materials Safety is responsible for overseeing the safe handling of hazardous materials aboard aircraft. The Federal Railroad Administration oversees the transportation of hazardous materials by rail. The U.S. Coast Guard regulates the bulk transport of hazardous materials by sea. The Federal Highway Administration (FHWA) is responsible for highway routing of hazardous materials and issuing highway safety permits.

Hazardous Substance and Waste Regulations

Resource Conservation and Recovery Act: The Resource Conservation and Recovery Act (RCRA) was adopted in 1976 (see 40 CFR Parts 238 – 282) and authorizes the U.S. EPA to control the generation, transportation, treatment, storage, and disposal of hazardous waste. The RCRA regulation specifies requirements for generators, including waste minimization methods, as well as for transporters and for treatment, storage, and disposal facilities. The RCRA regulation also includes restrictions on land disposal of wastes and used oil management standards. Under RCRA, hazardous wastes must be tracked from the time of generation to the point of disposal. In 1984, RCRA was amended with addition of the Hazardous and Solid Waste Amendments, which authorized increased enforcement by the U.S. EPA, more strict hazardous waste standards, and a comprehensive Underground Storage Tank program. Likewise, the Hazardous and Solid Waste Amendments focused on waste reduction and corrective action for hazardous releases. The use of certain techniques for the disposal of some hazardous wastes was specifically prohibited by the Hazardous and Solid Waste Amendments. Individual states may implement their own hazardous waste programs under RCRA, with approval by the U.S. EPA.

Comprehensive Environmental Response, Compensation and Liability Act: The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), which is often commonly referred to as Superfund, is a federal statute that was enacted in 1980 to address abandoned sites containing hazardous waste and/or contamination. CERCLA was amended in 1986 by the Superfund Amendments and Reauthorization Act (SARA), and by the Small Business Liability Relief and Brownfields Revitalization Act of 2002.

CERCLA contains prohibitions and requirements concerning closed and abandoned hazardous waste sites; establishes liability of persons responsible for releases of hazardous waste at these sites; and creates a trust fund to provide for cleanup when no responsible party can be identified. The trust fund is funded largely by a tax on the chemical and petroleum industries. CERCLA also provides federal jurisdiction to respond directly to releases or impending releases of hazardous substances that may endanger public health or the environment.

CERCLA also enabled the revision of the National Contingency Plan (NCP) which provided the guidelines and procedures needed to respond to releases and threatened releases of hazardous substances, pollutants, or contaminants. The NCP also established the National Priorities List, which identifies hazardous waste sites eligible for long-term remedial action financed under the federal Superfund program.

Prevention of Accidental Releases and Risk Management Programs: Requirements pertaining to the prevention of accidental releases are promulgated in Section 112(r) of the Clean Air Act Amendments of 1990 [42 U.S.C. Section 7401 et. seq.]. The objective of these requirements was to prevent the accidental release and to minimize the consequences of any such release of a listed regulated substance. Under these provisions, facilities that produce, process, handle or store a regulated substance have a duty to: 1) identify hazards which may result from releases using hazard assessment techniques; 2) design and maintain a safe facility and take steps necessary to prevent releases; and, 3) minimize the consequence of accidental releases that occur.

In accordance with the requirements in Section 112(r), U.S. EPA adopted implementing guidelines in 40 CFR Part 68. Under this part, stationary sources with more than a threshold quantity of a regulated substance shall be evaluated to determine the potential for and impacts of accidental releases from any processes subject to the federal risk management requirements. Under certain conditions, the owner or operator of a stationary source may be required to develop and submit a Risk Management Plan (RMP). RMPs consist of three main elements: a hazard assessment that includes off-site consequences analyses and a five-year accident history, a prevention program, and an emergency response program.

Hazardous Material Worker Safety Requirements

Occupational Safety and Health Administration Act: The federal Occupational Safety and Health Administration (OSHA) is an agency of the United States Department of Labor that was created by Congress under the Occupational Safety and Health Act in 1970. OSHA is the agency responsible for assuring worker safety and the handling and use of chemicals in the workplace. Under the authority of the Occupational Safety and Health Act of 1970, OSHA has adopted numerous regulations pertaining to worker safety (see 29 CFR Part 1910). These regulations set standards for safe workplaces and work practices, including the reporting of accidents and occupational injuries. Some OSHA regulations contain standards relating to hazardous materials handling to protect workers who handle toxic, flammable, reactive, or explosive materials, including workplace conditions, employee protection requirements, first aid, and fire protection, as well as material handling and storage. For example, facilities which use, store, manufacture, handle, process, or move hazardous materials are required to conduct employee safety training, have available and know how to use safety equipment, prepare illness and injury prevention programs, provide hazardous substance exposure warnings, prepare emergency response plans, and prepare a fire prevention plan.

OSHA's Hazard Communication Standard (HCS) requires chemical manufacturers, distributors, or importers to provide Safety Data Sheets (SDSs) (formerly known as Material Safety Data Sheets or MSDSs) to communicate the hazardous attributes of chemical products. As of June 1, 2015, the HCS requires new SDSs to be in a uniform format, and include the section numbers, the headings, and associated information under the following headings:

Section 1 - Identification includes product identifier; manufacturer or distributor name, address, phone number; emergency phone number; recommended use; restrictions on use.

Section 2 - Hazard(s) identification includes all hazards regarding the chemical; associated warning information.

Section 3 - Composition/information on ingredients includes chemical ingredients; trade secret claims.

Section 4 - First-aid measures includes important symptoms/effects, acute, delayed; required treatment.

Section 5 - Fire-fighting measures lists suitable extinguishing techniques, equipment; chemical hazards from fire.

Section 6 - Accidental release measures lists emergency procedures; protective equipment; proper methods of containment and cleanup.

Section 7 - Handling and storage lists precautions for safe handling and storage, including incompatibilities.

Section 8 - Exposure controls/personal protection lists OSHA's Permissible Exposure Limits (PELs); ACGIH Threshold Limit Values (TLVs); and any other exposure limit used or recommended by the chemical manufacturer, importer, or employer preparing the SDS where available as well as appropriate engineering controls; personal protective equipment (PPE).

Section 9 - Physical and chemical properties lists the chemical's characteristics.

Section 10 - Stability and reactivity lists chemical stability and possibility of hazardous reactions.

Section 11- Toxicological information includes routes of exposure; related symptoms, acute and chronic effects; numerical measures of toxicity.

Section 12 - Ecological information includes data from toxicity tests performed on aquatic and/or terrestrial organisms; potential to persist and degrade in the environment; results of tests of bioaccumulation potential; potential to move from soil to underground.[44]

Section 13 - Disposal considerations includes proper disposal practices, recycling or reclamation of the chemicals or its container; safe handling practices.[45]

Section 14 - Transport information includes classification information of shipping and transporting of hazardous chemical(s) by road, air, rail, or sea.[46]

Section 15 - Regulatory information includes safety, health, and environmental regulations specific for the product not elsewhere indicted on the SDS.

Section 16 - Other information includes the date of preparation or last revision.

It is important to note that since other agencies regulate the information presented in Sections 12 through 15, OSHA will not be enforcing these sections (see 29 CFR 1910.1200(g)(2)). Employers must ensure that SDSs are readily accessible to employees. For a detailed description of SDS contents see 29 CFR 1910.1200, Appendix D.

Procedures and standards for safe handling, storage, operation, remediation, and emergency response activities involving hazardous materials and waste are promulgated in 29 CFR Part 1910, Subpart H. Some key subsections in 29 CFR Part 1910, Subpart H are Section 1910.106 – Flammable Liquids, and Section 1910.120 – Hazardous Waste Operations and Emergency Response. In particular, the Hazardous Waste Operations and Emergency Response regulations contain requirements for worker training programs, medical surveillance for workers engaging in the handling of hazardous materials or wastes, and waste site emergency and remediation planning, for those who are engaged in specific clean-up, corrective action, hazardous material handling, and emergency response activities (see 29 CFR Part 1910 Subpart H, Section 1910.120 (a)(1)(i-v) and Section 1926.65 (a)(1)(i-v)).

Process Safety Management: As part of the numerous regulations pertaining to worker safety adopted by OSHA, specific requirements that pertain to Process Safety Management (PSM) of Highly Hazardous Chemicals were adopted in 29 CFR Part 1910 Subpart H, Section 1910.119 and 8 CCR Section 5189 to protect workers at facilities that have toxic,

[44] OSHA, Ecological Information Is Not Mandatory, OSHA Brief, accessed August 18, 2021. https://www.osha.gov/sites/default/files/publications/OSHA3514.pdf

[45] OSHA, Disposal Considerations Are Not Mandatory, OSHA Brief, accessed August 18, 2021. https://www.osha.gov/sites/default/files/publications/OSHA3514.pdf

[46] OSHA, Transport Information Is Not Mandatory, OSHA Brief, accessed August 18, 2021. https://www.osha.gov/sites/default/files/publications/OSHA3514.pdf

flammable, reactive or explosive materials. PSM program elements are aimed at preventing or minimizing the consequences of catastrophic releases of chemicals and include process hazard analyses, formal training programs for employees and contractors, investigation of equipment mechanical integrity, and an emergency response plan. Specifically, the PSM program requires facilities that use, store, manufacture, handle, process, or move hazardous materials to conduct employee safety training; have an inventory of safety equipment relevant to potential hazards; have knowledge on use of the safety equipment; prepare an illness prevention program; provide hazardous substance exposure warnings; prepare an emergency response plan; and prepare a fire prevention plan.

Emergency Action Plan: An Emergency Action Plan (EAP) is a written document required by OSHA standards promulgated in 29 CFR Part 1910, Subpart E, Section 1910.38(a) to facilitate and organize a safe employer and employee response during workplace emergencies. An EAP is required by all that are required to have fire extinguishers. At a minimum, an EAP must include the following: 1) a means of reporting fires and other emergencies; 2) evacuation procedures and emergency escape route assignments; 3) procedures to be followed by employees who remain to operate critical plant operations before they evacuate; 4) procedures to account for all employees after an emergency evacuation has been completed; 5) rescue and medical duties for those employees who are to perform them; and, 6) names or job titles of persons who can be contacted for further information or explanation of duties under the plan.

National Fire Regulations: The National Fire Codes (NFC), Title 45, published by the National Fire Protection Association (NFPA) contains standards for laboratories using chemicals, which are not requirements, but are generally employed by organizations in order to protect workers. These standards provide basic protection of life and property in laboratory work areas through prevention and control of fires and explosions, and also serve to protect personnel from exposure to non-fire health hazards.

In addition to the NFC, the NFPA adopted a hazard rating system which is promulgated in NFPA 704 – Standard System for the Identification of the Hazards of Materials for Emergency Response. NFPA 704 is a "standard (that) provides a readily recognized, easily understood system for identifying specific hazards and their severity using spatial, visual, and numerical methods to describe in simple terms the relative hazards of a material. It addresses the health, flammability, instability, and related hazards that may be presented as short-term, acute exposures that are most likely to occur as a result of fire, spill, or similar emergency[47]." In addition, the hazard ratings per NFPA 704 are used by emergency personnel to quickly and easily identify the risks posed by nearby hazardous materials in order to help determine what, if any, specialty equipment should be used, procedures followed, or precautions taken during the first moments of an emergency response. The scale is divided into four color-coded categories, with blue indicating level of health hazard, red indicating the flammability hazard, yellow indicating the chemical reactivity, and white containing special codes for unique hazards such as corrosivity and radioactivity.

[47] NFPA, FAQ for Standard 704, 2007 edition. http://www.nfpa.org/Assets/files/AboutTheCodes/704/704-2007_FAQs.pdf

Each hazard category is rated on a scale from 0 (no hazard; normal substance) to 4 (extreme risk). Table 3.3-4 summarizes what the codes mean for each category of hazard.

Table 3.3-4
NFPA 704 Hazards Rating Codes

Hazard Rating Code	Health (Blue)	Flammability (Red)	Reactivity (Yellow)	Special (White)
4 = Extreme	Very short exposure could cause death or major residual injury (extreme hazard)	Will rapidly or completely vaporize at normal atmospheric pressure and temperature, or, is readily dispersed in air and will burn readily. Flash point below 73 °F.	Readily capable of detonation or explosive decomposition at normal temperatures and pressures.	~~W~~ = Reacts with water in an unusual or dangerous manner.
3 = High	Short exposure could cause serious temporary or moderate residual injury	Liquids and solids that can be ignited under almost all ambient temperature conditions. Flash point between 73 °F and 100 °F.	Capable of detonation or explosive decomposition but requires a strong initiating source, must be heated under confinement before initiation, reacts explosively with water, or will detonate if severely shocked.	**OXY** = Oxidizer
2 = Moderate	Intense or continued but not chronic exposure could cause temporary incapacitation or possible residual injury.	Must be moderately heated or exposed to relatively high ambient temperature before ignition can occur. Flash point between 100 °F and 200 °F.	Undergoes violent chemical change at elevated temperatures and pressures, reacts violently with water, or may form explosive mixtures with water.	**SA** = Simple asphyxiant gas (includes nitrogen, helium, neon, argon, krypton and xenon).
1 = Slight	Exposure would cause irritation with only minor residual injury.	Must be heated before ignition can occur. Flash point over 200 °F.	Normally stable, but can become unstable at elevated temperatures and pressures	Not Applicable
0 = Insignificant	Poses no health hazard, no precautions necessary	Will not burn	Normally stable, even under fire exposure conditions, and is not reactive with water.	Not applicable

In addition to the information presented in Table 3.3-4, there are also a number of other physical or chemical properties that may cause a substance to be a fire hazard. With respect to determining whether any substance is classified as a fire hazard, SDSs list the National Fire Protection Association 704 flammability hazard ratings (e.g., NFPA 704). NFPA 704 is a standard that provides a readily recognized, easily understood system for identifying flammability hazards and their severity using spatial, visual, and numerical methods to describe in simple terms the relative flammability hazards of a material.

Although substances can have the same NFPA 704 Flammability Ratings Code, other factors can make each substance's fire hazard very different from each other. For this reason, additional chemical characteristics, such as auto-ignition temperature, boiling point, evaporation rate, flash point, lower explosive limit (LEL), upper explosive limit (UEL), and vapor pressure, are also considered when determining whether a substance is fire hazard. The following is a brief description of each of these chemical characteristics.

Auto-ignition Temperature: The auto-ignition temperature of a substance is the lowest temperature at which it will spontaneously ignite in a normal atmosphere without an external source of ignition, such as a flame or spark.

Boiling Point: The boiling point of a substance is the temperature at which the vapor pressure of the liquid equals the environmental pressure surrounding the liquid. Boiling is a process in which molecules anywhere in the liquid escape, resulting in the formation of vapor bubbles within the liquid.

Evaporation Rate: Evaporation rate is the rate at which a material will vaporize (evaporate, change from liquid to a vapor) compared to the rate of vaporization of a specific known material. This quantity is a represented as a unitless ratio. For example, a substance with a high evaporation rate will readily form a vapor which can be inhaled or explode, and thus have a higher hazard risk. Evaporation rates generally have an inverse relationship to boiling points (i.e., the higher the boiling point, the lower the rate of evaporation).

Flash Point: Flash point is the lowest temperature at which a volatile liquid can vaporize to form an ignitable mixture in air. Measuring the flash point of a liquid requires an ignition source. At the flash point, the vapor may cease to burn when the source of ignition is removed. There are different methods that can be used to determine the flashpoint of a solvent but the most frequently used method is the Tagliabue Closed Cup standard (ASTM D56), also known as the TCC. The flashpoint is determined by a TCC laboratory device which is used to determine the flash point of mobile petroleum liquids with flash point temperatures below 175 degrees Fahrenheit (79.4 degrees Centigrade).

Flash point is a particularly important measure of the fire hazard of a substance. For example, the Consumer Products Safety Commission (CPSC) promulgated Labeling and Banning Requirements for Chemicals and Other Hazardous Substances in 15 U.S.C. Section 1261 and 16 CFR Part 1500. Per the CPSC, the flammability of a product is defined in 16 CFR Part 1500.3 (c)(6) and is based on flash point. For example, a liquid needs to be labeled as: 1) “Extremely Flammable” if the flash point is below 20 degrees Fahrenheit; 2) “Flammable” if the flash point is above 20 degrees Fahrenheit but less than 100 degrees Fahrenheit; or 3) “Combustible” if the flash point is above 100 degrees Fahrenheit up to and including 150 degrees Fahrenheit.

Lower Explosive Limit (LEL): The lower explosive limit of a gas or a vapor is the limiting concentration (in air) that is needed for the gas to ignite and explode or the lowest concentration (percentage) of a gas or a vapor in air capable of producing a flash of fire in presence of an ignition source (e.g., arc, flame, or heat). If the concentration of a substance in air is below the LEL, there is not enough fuel to continue an explosion. In other words, concentrations lower than the LEL are "too lean" to burn. For example, methane gas has a LEL of 4.4 percent (at 138 degrees Centigrade) by volume, meaning 4.4 percent of the total volume of the air consists of methane. At 20 degrees Centigrade, the LEL for methane is 5.1 percent by volume. If the atmosphere has less than 5.1 percent methane, an explosion cannot occur even if a source of ignition is present. When the concentration of methane reaches 5.1 percent, an explosion can occur if there is an ignition source.

Upper Explosive Limit (UEL): The upper explosive limit of a gas or a vapor is the highest concentration (percentage) of a gas or a vapor in air capable of producing a flash of fire in presence of an ignition source (e.g., arc, flame, or heat). Concentrations of a substance in air above the UEL are "too rich" to burn.

Vapor Pressure: Vapor pressure is an indicator of a chemical’s tendency to evaporate into gaseous form.

Health Hazards Guidance: In addition to fire impacts, health hazards can also be generated due to exposure of chemicals present in both conventional as well as reformulated products. Using available toxicological information to evaluate potential human health impacts associated with conventional solvents and potential replacement solvents, the toxicity of the conventional solvents can be compared to solvents expected to be used in reformulated products. As a measure of a chemical’s potential health hazards, the following values need to be considered: the Threshold Limit Values (TLVs) established by the American Conference of Governmental Industrial Hygienists (ACGIH), OSHA’s Permissible Exposure Limits (PELs), the Immediately Dangerous to Life or Health (IDLH) levels recommended by the National Institute of Occupational Safety and Health (NIOSH), permissible exposure limits (PEL) established by OSHA, and health hazards developed by the National Safety Council. The following is a brief description of each of these values.

Threshold Limit Values (TLVs): The TLV of a chemical substance is a level to which it is believed a worker can be exposed day after day for a working lifetime without adverse health effects. The TLV is an estimate based on the known toxicity in humans or animals of a given chemical substance, and the reliability and accuracy of the latest sampling and analytical methods. The TLV for chemical substances is defined as a concentration in air, typically for inhalation or skin exposure. Its units are in parts per million (ppm) for gases and in milligrams per cubic meter (mg/m^3) for particulates. The TLV is a recommended guideline by ACGIH.

Permissible Exposure Limits (PEL): The PEL is a legal limit, usually expressed in ppm, established by OSHA to protect workers against the health effects of exposure to hazardous substances. PELs are regulatory limits on the amount or concentration of a substance in the air. A PEL is usually given as a time-weighted average (TWA), although some are short-term exposure limits (STEL) or ceiling limits. A TWA is the average exposure over a specified period of time, usually eight hours. This means that, for limited periods, a worker may be exposed to concentrations higher than the PEL, so long as the average concentration over eight hours remains lower. A short-term exposure limit is one that addresses the average exposure over a 15- to 30-minute period of maximum exposure during a single work shift. A ceiling limit is one that may not be exceeded for any period of time, and is applied to irritants and other materials that have immediate effects. The OSHA PELs are published in 29 CFR 1910.1000, Table Z1.

Immediately Dangerous to Life or Health (IDLH): IDLH is an acronym defined by NIOSH as exposure to airborne contaminants that is "likely to cause death or immediate or delayed permanent adverse health effects or prevent escape from such an environment." IDLH values are often used to guide the selection of breathing apparatus that are made available to workers or firefighters in specific situations.

<u>Oil and Pipeline Regulations and Oversight</u>

Oil Pollution Act: The Oil Pollution Act was signed into law in 1990 to give the federal government authority to better respond to oil spills (see 33 U.S.C. Section 2701). The Oil Pollution Act improved the federal government's ability to prevent and respond to oil spills, including provision of money and resources. The Oil Pollution Act establishes polluter liability, gives states enforcement rights in navigable waters of the State, mandates the development of spill control and response plans for all vessels and facilities, increases fines and enforcement mechanisms, and establishes a federal trust fund for financing clean-up.

The Oil Pollution Act also establishes the National Oil Spill Liability Trust Fund to provide financing for cases in which the responsible party is either not readily identified, or refuses to pay the cleanup/damage costs. In addition, the Oil Pollution Act expands provisions of the National Oil and Hazardous Substances Pollution Contingency Plan, more commonly called the National Contingency Plan, requiring the federal government to direct all public and private oil spill response efforts. It also requires area committees, composed of federal, state, and local government officials, to develop detailed, location-specific area contingency plans. In addition, the Oil Pollution Act directs owners and operators of vessels, and certain facilities that pose a serious threat to the environment, to prepare their own specific facility response plans. The Oil Pollution Act increases penalties for regulatory non-compliance by responsible parties; gives the federal government broad enforcement authority; and provides individual states the authority to establish their own laws governing oil spills, prevention measures, and response methods. The Oil Pollution Act requires oil storage facilities and vessels to submit to the Federal government plans detailing how they will respond to large discharges. The U.S. EPA has published regulations for aboveground storage facilities and the U.S. Coast Guard has done the same for oil tankers.

Oil Pollution Prevention Regulation: In 1973, the U.S. EPA issued the Oil Pollution Prevention regulation (see 40 CFR Part 112)**,** to address the oil spill prevention provisions contained in the Clean Water Act of 1972. The Spill Prevention, Control, and Countermeasure (SPCC) Rule is part of the Oil Pollution Prevention regulations (see 40 CFR Part 112, Subparts A – C). Any facility storing more than 1,320 gallons of petroleum product is required to prepare a plan for oil spill prevention, preparedness, and response to prevent oil discharges to navigable waters and adjoining shorelines. The SPCC Rule requires specific facilities to prepare, amend, and implement SPCC Plans. SPCC Plans require applicable facilities to take steps to prevent oil spills including: 1) using suitable storage containers/tanks; 2) providing overfill prevention (e.g., high-level alarms); 3) providing secondary containment for bulk storage tanks; 4) providing secondary containment to catch oil spills during transfer activities; and, 5) periodically inspecting and testing pipes and containers.

U.S. Department of Transportation, Office of Pipeline Safety: The Office of Pipeline Safety, within the U.S. DOT, Pipeline and Hazards Material Safety Administration, has jurisdictional responsibility for developing regulations and standards to ensure the safe and secure movement of hazardous liquid and gas pipelines under its jurisdiction in the United States. The Office of Pipeline Safety has the following key responsibilities:

- Support the operation of, and coordinate with the U.S. Coast Guard on the National Response Center and serve as a liaison with the Department of Homeland Security and the Federal Emergency Management Agency on matters involving pipeline safety;

- Develop and maintain partnerships with other federal, state, and local agencies, public interest groups, tribal governments, and the regulated industry and other underground utilities to address threats to pipeline integrity, service, and reliability and to share responsibility for the safety of communities;

- Administer pipeline safety regulatory programs and develops regulatory policy involving pipeline safety;

- Oversee pipeline operator implementation of risk management and risk-based programs and administer a national pipeline inspection and enforcement program;

- Provide technical and resource assistance for state pipeline safety programs to ensure oversight of intrastate pipeline systems and educational programs at the local level; and,

- Support the development and conduct of pipeline safety training programs for federal and state regulatory and compliance staff and the pipeline industry.

49 CFR Parts 178 – 185 relates to the role of transportation, including pipelines, in the United States. 49 CFR Parts 186 –199 establishes minimum pipeline safety standards. The Office of the State Fire Marshal works in partnership with the Federal Pipeline and Hazardous Materials Safety Administration to assure pipeline operators are meeting

requirements for safe, reliable, and environmentally sound operation of their facilities for intrastate pipelines within California.

Chemical Facility Anti-Terrorism Standards: The Federal Department of Homeland Security is responsible for implementing the Chemical Facility Anti-Terrorism Standards that were adopted in 2007 (see 6 CFR Part 27). These standards establish risk-based performance standards for the security of chemical facilities and require covered chemical facilities to prepare Security Vulnerability Assessments, which identify facility security vulnerabilities, and to develop and implement Site Security Plans.

3.3.1.3 State Regulations

Hazardous Materials and Waste Regulations

Hazardous Waste Control Law: California's Hazardous Waste Control Law is administered by the California Environmental Protection Agency (CalEPA) to regulate hazardous wastes within the State of California. While the California Hazardous Waste Control Law is generally more stringent than RCRA, both the state and federal laws apply in California. The California Department of Toxic Substances Control (DTSC) is the primary agency in charge of enforcing both the federal and state hazardous materials laws in California. The DTSC regulates hazardous waste, oversees the cleanup of existing contamination, and pursues ways to reduce hazardous waste produced in California. The DTSC regulates hazardous waste in California under the authority of RCRA, the Hazardous Waste Control Law, and the HSC. Under the direction of the CalEPA, the DTSC maintains the Cortese and Envirostor databases of hazardous materials and waste sites as specified under Government Code Section 65962.5.

The Hazardous Waste Control Law (22 CCR Chapter 11, Appendix X) also lists 791 chemicals and approximately 300 common materials which may be hazardous; establishes criteria for identifying, packaging, and labeling hazardous wastes; prescribes management controls; establishes permit requirements for treatment, storage, disposal, and transportation; and identifies some wastes that cannot be disposed of in landfills.

California Occupational Safety and Health Administration: The California Occupational Safety and Health Administration (CalOSHA) is the primary state agency responsible for worker safety in the handling and use of chemicals in the workplace. CalOSHA requires employers to monitor worker exposure to listed hazardous substances and notify workers of exposure (8 CCR Sections 337 – 340). The regulations specify requirements for employee training, availability of safety equipment, accident-prevention programs, and hazardous substance exposure warnings. CalOSHA's standards are generally more stringent than federal regulations.

In response to a 2012 refinery fire in Richmond, California, CalOSHA amended its Process Safety Management Regulation (Title 8 CCR Section 5189) in 2017 and introduced a new refinery safety order enforced by CalOSHA's Process Safety Management (PSM) Unit, adding Section 5189.1 to Title 8 of the CCR. The elements outlined in the regulation require refinery employers to:

- Conduct *Damage Mechanism Reviews* for processes that result in equipment or material degradation. Physical degradation, such as corrosion and mechanical wear, are common technical causes of serious process failures.

- Conduct a *Hierarchy of Hazard Controls Analysis* to encourage refinery management to implement the most effective safety measures when considering competing demands and costs when correcting hazards.

- Implement a *Human Factors Program*, which requires analysis of human factors such as staffing levels, training and competency, fatigue and other effects of shift work, and the human-machine interface.

- Develop, implement and maintain written procedures for the *Management of Organizational Change* to ensure that plant safety remains consistent during personnel changes.

- Utilize *Root Cause Analysis* when investigating any incident that results in, or could have reasonably resulted in, a major incident.

- Perform and document a *Process Hazard Analysis* of the effectiveness of safeguards that apply to particular processes and identify, evaluate and control hazards associated with each process.

- Understand the attitudes, beliefs, perceptions and values that employees share in relation to safety and evaluate responses to reports of hazards by implementing and maintaining an effective *Process Safety Culture Assessment* program[48].

Hazardous Materials Release Notification: Many California statutes require emergency notification when a hazardous chemical is released, including:

- HSC Sections 25270.7, 25270.8, 25510, and 25510.3;

- Vehicle Code Section 23112.5;

- Public Utilities Code Section 7673 (General Orders #22-B, 161);

- Government Code Sections 51018 and 8670.25.5(a);

- Water Code Sections 13271 13272; and,

- Labor Code Section 6409.1(b)(10).

California Accidental Release Prevention (CalARP) Program: The California Accidental Release Prevention Program (19 CCR Division 2, Chapter 4.5) requires the preparation of

[48] State of California, Department of Industrial Relations, News Release 2017-37, Landmark Workplace Safety and Health Regulation Approved to Reduce Risk of Major Incidents at Oil Refineries in California, May 18, 2017. https://www.dir.ca.gov/DIRNews/2017/2017-37.pdf, accessed November 9, 2020.

Risk Management Plans (RMPs). CalARP requires stationary sources with more than a threshold quantity of a regulated substance to be evaluated to determine the potential for and impacts of accidental releases from any processes subject to state risk management requirements. RMPs are documents prepared by the owner or operator of a stationary source containing detailed information including: 1) regulated substances held onsite at the stationary source; 2) offsite consequences of an accidental release of a regulated substance; 3) the accident history at the stationary source; 4) the emergency response program for the stationary source; 5) coordination with local emergency responders; 6) hazard review or process hazard analysis; 7) operating procedures at the stationary source; 8) training of the stationary source's personnel; 9) maintenance and mechanical integrity of the stationary source's physical plant; and, 10) incident investigation. The CalARP program is implemented at the local government level by Certified Unified Program Agencies (CUPAs) and contract agencies known as Participating Agencies or Administering Agencies (AAs). Typically, local fire departments are the administering agencies of the CalARP program because they frequently are the first responders in the event of a release. Each CUPA with a refinery shall develop an integrated alerting and notification system, in coordination with local emergency management agencies, unified program agencies, local first response agencies, petroleum refineries, and the public, to be used to notify the community surrounding a petroleum refinery in the event of an incident at the refinery warranting the use of the automatic notification system. The integrated alerting and notification system shall include the following:

1. Text messaging;
2. Calls to landline and cellular telephones;
3. Activation of the Emergency Alert System;
4. National Weather Service alerts to National Oceanic and Atmospheric Administration radios;
5. Social media communications;
6. New technologies when developed; and
7. An audible alarm.

The integrated alerting and notification system shall alert and notify the communities surrounding a petroleum refinery, including schools, public facilities, hospitals, transient and special needs populations, and residential care homes. The area of the community to be alerted and notified shall be determined by the local implementing agency in coordination with unified program agencies, local first response agencies, petroleum refineries, and the public.

If an integrated alerting and notification system is not implemented by January 1, 2018, the local implementing agency shall, in coordination with the unified program agency, local first response agencies, petroleum refineries, and the public, determine an appropriate integrated alerting and notification system to be developed consistent with subdivisions (a) and (b) and, on or before January 1, 2019, must develop a schedule for developing and implementing the integrated alerting and notification system.

The local implementing agency, through an interagency agreement or memorandum of understanding with the CUPA and the county's operational area coordinator, shall manage, operate, coordinate, and maintain the integrated alerting and notification system. A petroleum refinery shall immediately call the emergency 9-1-1 telephone number and notify the CUPA, in the event of an incident warranting the use of the integrated alerting and notification system.

Unified Hazardous Waste and Hazardous Materials Management Regulatory Program: The Unified Hazardous Waste and Hazardous Materials Management Regulatory Program (Unified Program) as promulgated by CalEPA in CCR, Title 27, Chapter 6.11 requires the administrative consolidation of six hazardous materials and waste programs (program elements) under one agency, a CUPA. The Unified Program administered by the State of California consolidates, coordinates, and makes consistent the administrative requirements, permits, inspections, and enforcement activities for the state's environmental and emergency management programs, which include Hazardous Waste Generator and On-Site Hazardous Waste Treatment Programs ("Tiered Permitting"); Above ground SPCC Program; Hazardous Materials Release Response Plans and Inventories (business plans); the CalARP Program; the UST Program; and the Uniform Fire Code Plans and Inventory Requirements. The Unified Program is implemented at the local government level by CUPAs.

Hazardous Materials Management Act: HSC, Division 20, Chapter 6.95 requires any business handling more than a specified amount of hazardous or extremely hazardous materials, to submit a Hazardous Materials Business Plan to its CUPA. Business plans must include an inventory of the types, quantities, and locations of hazardous materials at the facility. Businesses are required to update their business plans at least once every three years and the chemical portion of their plans every year. Also, business plans must include emergency response plans and procedures to be used in the event of a significant or threatened significant release of a hazardous material. These plans need to identify the procedures to follow for immediate notification to each school superintendent within one-half mile of an acutely hazardous material release[49], all appropriate agencies and personnel of a release, identification of local emergency medical assistance appropriate for potential accident scenarios, contact information for all company emergency coordinators, a listing and location of emergency equipment at the business, an evacuation plan, and a training program for business personnel. The requirements for hazardous materials business plans are specified in the HSC and 19 CCR.

Hazardous Materials Transportation in California: California regulates the transportation of hazardous waste originating or passing through the State in Title 13, CCR. The California Highway Patrol (CHP) and the California Department of Transportation (Caltrans) have primary responsibility for enforcing federal and State regulations and

[49] HSC Section 25510.3. http://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=HSC&sectionNum=25510.3.

responding to hazardous materials transportation emergencies. The CHP enforces materials and hazardous waste labeling and packing regulations that prevent leakage and spills of material in transit and provide detailed information to cleanup crews in the event of an incident. Vehicle and equipment inspection, shipment preparation, container identification, and shipping documentation are all part of the responsibility of the CHP. Caltrans has emergency chemical spill identification teams at locations throughout California.

California Fire Code: While NFC Standard 45 and NFPA 704 are regarded as nationally recognized standards, the California Fire Code (24 CCR) also contains state standards for the use and storage of hazardous materials and special standards for buildings where hazardous materials are found. Some of these regulations consist of amendments to NFC Standard 45. California Fire Code regulations require emergency pre-fire plans to include training programs in first aid, the use of fire equipment, and methods of evacuation.

3.3.1.4 Local Regulations

South Coast AQMD

South Coast AQMD Rule 1118 – Control of Emissions from Refinery Flares: Rule 1118 establishes requirements to notify the Executive Officer via the Web-Based Flare Event Notification System within one hour from the start of any unplanned flare event with emissions exceeding either 100 pounds of VOC or 500 pounds of SO2, or exceeding 500,000 standard cubic feet of flared vent gas.

South Coast AQMD Rule 1166 – Volatile Organic Compound Emissions from Decontamination of Soil: Rule 1166 establishes requirements to control the emission of VOCs from excavating, grading, handling, and treating soil contaminated from leakage, spillage, or other means of VOCs deposition. Rule 1166 stipulates that any parties planning on excavating, grading, handling, transporting, or treating soils contaminated with VOCs must first apply for and obtain, and operate pursuant to, a mitigation plan approved by the Executive Officer prior to commencement of operation. BACT is required during all phases of remediation of soil contaminated with VOCs. Rule 1166 also sets forth testing, record keeping and reporting procedures that must be followed at all times. Non-compliance with Rule 1166 can result in the revocation of the approved mitigation plan, the owner and/or the operator being served with a Notice of Violation for creating a public nuisance, or an order to halt the offending operation until the public nuisance is mitigated to the satisfaction of the Executive Officer.

South Coast AQMD Rule 1180 – Refinery Fenceline and Community Air Monitoring: Rule 1180 affects refineries, requiring real-time fenceline air monitoring systems that provides air quality information to the public about levels of various criteria air pollutants, volatile organic compounds, metals, and other compounds, at or near the property boundaries of petroleum refineries and in nearby communities.

South Coast AQMD Rule 1466 – Control of Particulate Emissions from Soils with Toxic Air Contaminants: Rule 1466 affects operations conducting earth-moving activities of soil that has been identified by the U.S. EPA, the DTSC, the State Water Board, the Regional Water Board, or a county, local, or state regulatory agency to contain one or more of the applicable toxic air contaminants listed in the rule, and the site has been designated by one or more of the aforementioned agencies. While earth-moving activities occur, the owner or operator must conduct continuous direct-reading near real-time ambient monitoring. If PM10 concentration over two hours exceeds 25 μg/m^3, the earth-moving activities must cease, dust suppressant must be applied, or implement other dust control measures until the concentration decreases to below 25 μg/m^3 averaged over 30 minutes.

South Coast AQMD Rules 2011 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions and 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions: Rule 2011 and 2012 requirements shall apply to any RECLAIM SOx or NOx source, or SOx or NOx process unit. The SOx and NOx sources and process units regulated by this rule include, but are not limited to:

Boilers	Fluid Catalytic Cracking Units (FCCUs)
Internal Combustion Engines	Dryers
Heaters	Fume Incinerators/Afterburners
Gas Turbines	Test Cells
Furnaces	Tail Gas Units
Kilns and Calciners	Sulfuric Acid Production
Ovens	Waste Incinerators

<u>Regulations from Other Local Agencies</u>

Since all of the facilities subject to the proposed project are located in Los Angeles County, the following discussion relative to regulations of other local agencies are focused on local agencies with jurisdictional authority within Los Angeles County. In addition to the South Coast AQMD, the following local agencies which are located throughout Los Angeles County and their respective fire departments have a variety of locally applicable laws that regulate reporting, storage and handling of hazardous materials and wastes.

Office of Emergency Management: The Office of Emergency Management is responsible for organizing and directing the preparedness efforts of the Emergency Management Organization of Los Angeles County. Los Angeles County's policies towards hazardous materials management include enforcing stringent site investigations for factors related to hazards; limiting the development in high hazard areas, such as floodplains, high fire hazard areas, and seismic hazard zones; facilitating safe transportation, use, and storage of hazardous materials; supporting lead paint abatement; remediating Brownfield sites; encouraging the purchase of homes on the Federal Emergency Management Agency (FEMA) Repeat Hazard list and designating the land as open space; enforcing restrictions on access to important energy sites; limiting development downslope from aqueducts; promoting safe alternatives to chemical-based products in households; and prohibiting development in floodways. The county has defined effective emergency response management capabilities to include supporting county emergency providers with reaching their response time goals; promoting the participation and coordination of emergency response management between cities and other counties at all levels of government;

coordinating with other county and public agency emergency planning and response activities; and encouraging the development of an early warning system for tsunamis, floods and wildfires.

Certified Unified Program Agencies: CUPAs within Los Angeles County require refineries to conduct Program Level 4 inspections and audits of refineries pursuant to the CalARP program (19 CCR Section 2762.0.1[50]). The purpose of Program Level 4 is to prevent major incidents at petroleum refineries in order to protect the health and safety of communities and the environment (19 CCR Section 2762.0.2). "Major incident" means an event within or affecting a process that causes a fire, explosion or release of a highly hazardous material, and has the potential to result in death or serious physical harm (as defined in California Labor Code Section 6432(e)), which describes "Serious physical harm," as meaning any injury or illness, specific or cumulative, occurring the place of employment or in connection with any employment or in connection with any employment, that results in any of the following:

1) Inpatient hospitalization for purposes other than medical observation.
2) The loss of any member of the body.
3) Any serious degree of permanent disfigurement.
4) Impairment sufficient to cause a part of the body or the function of an organ to become permanently and significantly reduced in efficiency on or off the job, including but not limited to, depending on the severity, second-degree or worse burns, crushing injuries including internal injuries even though skin surface may be intact, respiratory illnesses, or broken bones.

Incidents resulting in an officially declared public shelter-in place, or evacuation order are also considered major incidents. (19 CCR Section 2735.3 (ii)).

3.3.2 Emergency Response to Hazardous Materials and Waste Incidents

3.3.2.1 Federal

The Federal Emergency Management Agency (FEMA) exists to "raise risk awareness, educate in risk reduction options, and help take action before disasters; alert, warn, and message, coordinate Federal response, and apply and manage resources during disasters; and coordinate Federal recovery efforts, provide resources, and apply insight to future risk after disasters."[51] In preparation for future incidents, FEMA has produced the Authorized Equipment List (AEL) which, along with the Standardized Equipment List created by the Interagency Board (IAB) for Emergency Preparedness and Response, provides equipment recommendations for various missions (e.g., law enforcement: preventive radiation/nuclear detection) and sublists (e.g., detection, decontamination, medical); FEMA offers Preparedness Grants for equipment types approved

[50] CCR, Title 19, Division 2, Chapter 4.5, Article 6.5 – CalARP Program 4 Prevention Program, accessed November 9, 2020. https://govt.westlaw.com/calregs/Browse/Home/California/CaliforniaCodeofRegulations?guid=I0F501A53539C437A864E155B230DCBEA&originationContext=documenttoc&transitionType=Default&contextData=(sc.Default)

[51] FEMA, "We are FEMA: Helping People Before, During and After Disasters" https://www.fema.gov/sites/default/files/2020-03/publication-one_english_2019.pdf

under the AEL. To address the issue of jurisdictions' limited resources, organizations are directed to implement the resource management principles of the National Incident Management System (NIMS) which connect neighboring jurisdictions through mutual aid agreement, private sector partnerships, and volunteer organization involvement. If an incident occurs, the organization responsible for the release is required by law to notify the National Response Center at 1-800-424-8802, a 24-hours per day center run by the United States Coast Guard (USCG). The National Response Center will contact a designated FEMA On-Scene Coordinator (OSC) in the region, alongside state, local, tribal, and territorial emergency personnel who determine the status of the response and how much Federal involvement is necessary. OSC evaluate whether the cleanup was appropriate, timely, and minimized human and environmental damage.[52] An OSC is an agent of either EPA or USCG: EPA OSC have primary responsibility for spills and releases to inland areas and waters while USCG OSC have responsibility for coastal waters and the Great Lakes.[53]

The National Incident Management System (NIMS) focuses on resource management before and during an incident. "Resource management preparedness involves: identifying and typing resources; qualifying, certifying, and credentialing personnel; planning for resources; and acquiring, storing, and inventorying resources." By identifying and typing resources, common language can be established for defining minimum capabilities expected of personnel, teams, facilities, equipment, and supplies; and enabling communities to plan for, request, and have confidence in the resources they receive. FEMA is responsible for developing and maintaining resource typing definitions. Training personnel and stockpiling resources ensure that, when an incident occurs, the most effective and efficient response can be executed. Personnel responding to an incident are organized according a standardized approach to command, control, and coordination, the Incident Command System (ICS). Depending on the situation, a single Incident Commander or group of Unified Command will oversee a team consisting of a public information officer, safety officer, liaison officer, and operations, planning, logistics, and finance/administration teams each with their own chief. NIMS staff and representatives from other jurisdictions coordinate at Emergency Operations Centers (EOC). During an incident, the Incident Commander(s) identify, order, mobilize, and track resources; followed by demobilizing, and reimbursing and restocking supplies accordingly afterwards.[54]

The EPA Environmental Response Team (ERT) "responds to oil spills, chemical, biological, radiological, and nuclear incidents and large-scale national emergencies, including homeland security incidents…when requested or when state and local first responder capabilities have been exceeded."[55] In addition to the EPA OSC, the ERT consists of technical experts who advise at the scene of hazardous substance releases. Special teams include: the Radiological Emergency Response Team (RERT), the Chemical, Biological, Radiological, and Nuclear Consequence Management Advisory Division (CBRN CMAD), and the National Criminal Enforcement Response Team (NCERT).[56]

[52] FEMA, Hazardous Materials Incidents, Guidance for State, Local, Tribal, Territorial, and Private Sector Partners, August 2019. https://www.fema.gov/sites/default/files/2020-07/hazardous-materials-incidents.pdf
[53] U.S. EPA, EPA's On-Scene Coordinators. https://www.epa.gov/emergency-response/epas-scene-coordinators-oscs
[54] FEMA, National Incident Management System, Third Edition, October 2017. https://www.fema.gov/sites/default/files/2020-07/fema_nims_doctrine-2017.pdf
[55] U.S. EPA, EPA's Role in Emergency Response. https://www.epa.gov/emergency-response/epas-role-emergency-response
[56] U.S. EPA, EPA's Role in Emergency Response – Special Teams. https://www.epa.gov/emergency-response/epas-role-emergency-response-special-teams

3.3.2.2 State

The California Office of Emergency Services (CalOES) exists to enhance safety and preparedness in California through strong leadership, collaboration, and meaningful partnerships. The goal of CalOES is to protect lives and property by effectively preparing for, preventing, responding to, and recovering from all threats, crimes, hazards, and emergencies. CalOES is under the Fire and Rescue Division, coordinates statewide implementation of hazardous materials accident prevention and emergency response programs for all types of hazardous materials incidents and threats. In response to any hazardous materials emergency, CalOES is called upon to provide state and local emergency managers with emergency coordination and technical assistance.

Pursuant to the Emergency Services Act, the State of California has developed an Emergency Response Plan to coordinate emergency services provided by federal, state, and local government agencies and private persons. Response to hazardous materials incidents is one part of this plan. The Plan is administered by CalOES which coordinates the responses of other agencies. Six mutual aid and Local Emergency Planning Committee (LEPC) regions have been identified for California, as required by the federal Superfund Amendments and Re-authorization Act (SARA). California is divided into three areas of the state designated as the Coastal (Region II, which includes 16 counties with 151 incorporated cities and a population of about eight million people), Inland (Region III, Region IV and Region V, which includes 31 counties with 123 incorporated cities and a population of about seven million people), and Southern (Region I and Region VI, which includes 11 counties with 226 incorporated cities and a population of about 21.6 million people). At the federal level, the U.S. DOT has overlapping jurisdiction over portions of Region I and Region VI, which are also within the jurisdiction of South Coast AQMD.

In addition, pursuant to the Hazardous Materials Release Response Plans and Inventory Law of 1985, local agencies are required to develop "area plans" for response to releases of hazardous materials and wastes. These emergency response plans depend to a large extent on the business plans submitted by persons who handle hazardous materials. An area plan must include pre-emergency planning of procedures for emergency response, notification, coordination of affected government agencies and responsible parties, training, and follow-up.

With respect to suppliers and sellers of hazardous materials, HSC Section 25506 specifically requires all businesses handling hazardous materials to submit a business emergency response plan to assist local administering agencies in the emergency release or threatened release of a hazardous material. Business emergency response plans generally require the following:

1. Identification of individuals who are responsible for various actions, including reporting, assisting emergency response personnel and establishing an emergency response team;

2. Procedures to notify the administering agency, the appropriate local emergency rescue personnel, and the CalOES;

3. Procedures to mitigate a release or threatened release to minimize any potential harm or damage to persons, property or the environment;

4. Procedures to notify the necessary persons who can respond to an emergency within the facility;

5. Details of evacuation plans and procedures;

6. Descriptions of the emergency equipment available in the facility;

7. Identification of local emergency medical assistance; and

8. Training (initial and refresher) programs for employees in:

    a. The safe handling of hazardous materials used by the business;
    b. Methods of working with the local public emergency response agencies;
    c. The use of emergency response resources under control of the handler; and
    d. Other procedures and resources that will increase public safety and prevent or mitigate a release of hazardous materials.

In general, every county or city and all facilities using a minimum amount of hazardous materials are required to formulate detailed contingency plans to eliminate, or at least minimize, the possibility and effect of fires, explosion, or spills. In cooperation with the CalOES, local jurisdictions have enacted ordinances that set standards for area and business emergency response plans. These requirements include immediate notification, mitigation of an actual or threatened release of a hazardous material, and evacuation of the emergency area.

3.3.2.3 Local

The Sheriff, Fire, Health Services, and Public Works departments, and the Chief Executive Office, Office of Emergency Management respond to emergencies in the County of Los Angeles. In particular, the Fire Department Hazardous Materials program addresses chemical and explosive threats, provides 24-hour emergency services, and operates at four locations distributed throughout county: Haz Mat 43 – 921 South Stimson Avenue, La Puente, CA 91746; Haz Mat 105 – 18915 South Santa Fe Avenue, Compton, CA 90221; Haz Mat 129 – 42110 6th Street West, Lancaster, CA 93534; and Haz Mat 150 – 19190 Golden Valley Road, Santa Clarita, CA 91387.[57]

3.3.3 Hazardous Materials Incidents

Refineries can experience unanticipated conditions which result in hazardous chemicals to be released into the ambient air. These events can include situations in which chemical emissions exceed permit limits during an accidental release, normal controls are bypassed, or the effectiveness of the normal controls is reduced. During refinery incidents, large amounts of chemical-rich emissions may be carried to populated areas and cause exposure to a number of compounds. The extent of exposure depends on factors such as the quantity released, chemical properties, and meteorological conditions. In addition to these factors, understanding the chemicals that are involved in a release, the amount emitted, the acute and chronic health effects of exposure, and the air monitoring capabilities for chemicals can help responders characterize the risk

[57] County of Los Angeles Fire Department, Emergency Operations. https://fire.lacounty.gov/emergency-operations/

associated with a refinery incident or "major" incident. Furthermore, members of nearby communities may experience cumulative exposure from multiple events over time and may be more susceptible to pollution-related health problems. Exposures may occur during the transportation of hazardous materials through communities en route to a refinery. The movement of hazardous materials implies a degree of risk, depending on the materials being moved, the mode of transport, and numerous other factors (e.g., weather).

Hazardous materials move through the region by a variety of modes: truck, rail, air, ship, and pipeline. The movement of hazardous materials implies a degree of risk, depending on the materials being moved, the mode of transport, and numerous other factors (e.g., weather and road conditions). According to the Office of Hazardous Materials Safety (OHMS) in the U.S. DOT, hazardous materials shipments can be regarded as equivalent to deliveries, but any given shipment may involve one or more movements or trip segments, which may occur by different routes (e.g., rail transport with final delivery by truck). According to the Commodity Flow Survey data, there were more than 2.9 billion tons of hazardous materials shipments in the United States in 2017 (the last year for which data is available). Table 3.3-5 indicates that trucks move more than 60 percent and pipeline accounts for approximately 23 percent of all hazardous materials transported from a location in the United States. By contrast, rail accounts for only three percent of transported materials.[58]

Table 3.3-5
Movement of Hazardous Materials in the United States in 2017

Mode	Quantity of Hazardous Materials Transported (thousand tons)	Percent of Total Hazardous Materials Movement by Mode of Transportation
Truck	1,814,848	61.1%
Rail	90,387	3.0%
Water	304,189	10.2%
Pipeline	679,846	22.9%
Total	**2,967,965**	**100.0%**

Single mode air, multiple modes, and other modes also comprise part of the total, but have not been listed. Source: U.S. DOT[59]

California Hazardous Materials Incident Reporting System: The California Hazardous Materials Incident Reporting System (CHMIRS) is a post-incident reporting system to collect data on incidents involving the accidental release of hazardous materials in California. Information on accidental releases of hazardous materials is reported to and maintained by Cal EMA. While information on accidental releases is reported to Cal EMA, Cal EMA no longer conducts statistical

58 USDOT, 2020. Table H1a: Hazardous Material Shipment Characteristics by Mode of Transportation for the United States: 2017. United States: 2017; 2017 Economic Census and 2017 Commodity Flow Survey. Issued September 2020. https://www.census.gov/content/dam/Census/library/publications/2017/econ/ec17tcf-us.pdf.

59 USDOT, 2020. Table H1a: Hazardous Material Shipment Characteristics by Mode of Transportation for the United States: 2017. United States: 2017; 2017 Economic Census and 2017 Commodity Flow Survey. Issued September 2020. Available at https://www.census.gov/content/dam/Census/library/publications/2017/econ/ec17tcf-us.pdf

evaluations of the releases, e.g., total number of releases per year for the entire State, or data by county. The U.S. DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) provides access to retrieve data from the Incident Reports Database, which also includes non-pipeline incidents, e.g., truck and rail events. Incident data and summary statistics, e.g., release date, geographical location (state and county) and type of material released, are available online from the Hazmat Incident Database.

Table 3.3-6 provides a summary of the reported hazardous material incidents for Los Angeles, Orange, Riverside, and San Bernardino counties for 2012 through 2014 from the Hazmat Incident Database. Data presented is for the entire county and not limited to the portion of the county located within the jurisdiction of the South Coast AQMD.

Table 3.3-6
Reported Hazardous Materials Incidents for 2012 - 2014

County	2012	2013	2014
Los Angeles	286	337	287
Orange	270	63	88
Riverside	55	43	50
San Bernardino	261	348	351
Total	**872**	**791**	**776**

In 2012, there were a total of 872 incidents reported for Los Angeles, Orange, Riverside and San Bernardino counties. In 2013, there were a total of 791 incidents reported for Los Angeles, Orange, Riverside and San Bernardino counties, and in 2014 a total of 776 incidents for these four counties. Over the three-year period, San Bernardino and Los Angeles counties accounted for the largest number of incidents, followed by Orange and Riverside counties. As noted in Table 3.3-6, the number of incidents has reduced over the years.

CalOES is required to collect hazardous materials release notifications from the public, businesses and emergency response agency to ensure local and state agencies are alerted to possible hazardous materials releases and to dispatch emergency resources for both notification and response to hazardous materials incidents. Reports of annual notifications are available to the public and can be downloaded for specific years.[60]

3.3.4 Hazards Associated With Air Pollution Control and Refinery Processes

The South Coast AQMD has evaluated the hazards associated with previous AQMPs, proposed South Coast AQMD rules, and non-South Coast AQMD projects where the South Coast AQMD is the Lead Agency pursuant to CEQA. The analyses covered a range of potential air pollution control technologies and equipment. For example, CEQA documents prepared for the previous AQMPs and South Coast AQMD rules, such as the March 2017 Program EIR for the 2016 AQMP and the December 2015 Final PEA for NOx RECLAIM, upon which this SEA relies, have specifically evaluated hazard impacts from new or modified add-on air pollution control

[60] CalOES, Spill Release Archive Files. https://www.caloes.ca.gov/Governments-Tribal/Plan-Prepare/Spill-Release-Reporting, accessed August 23, 2021.

equipment that use hazardous materials (e.g., SCRs using ammonia and catalysts, scrubbers using chemicals, etc.).

U.S. EPA's Toxics Release Inventory (TRI) Program is a resource for learning about toxic chemical releases into the air, as well as into land and water. The TRI Program requires certain industrial facilities in the US to report annual release data in accordance to the Emergency Planning and Community Right-to-Know Act (EPCRA). The TRI database contains data by facility and by year. The focus of this report is the potential health effects of chemicals emitted from refineries. This is not an assessment of the potential health effects of all emissions. However, California Office of Environmental Health Hazard Assessment (OEHHA) found it useful to understand the relative routine and non-routine emissions to compare with the health effects of those chemicals to assist CARB in prioritizing chemicals for air monitoring. CARB tracks data pertaining to releases of TAC emissions from 28 California refineries in its California Emission Inventory Development and Reporting System (CEIDARS) database. The top 10 pollutants routinely released from 28 refineries in California in the greatest quantities per year based on 2009-2012 data are displayed in Table 3.3-7.

Table 3.3-7
Toxic Air Contaminants (TACs) with the
Top Ten Highest Routine Emissions from California Refineries

Chemical Name	**Emissions (lbs/year)**
Ammonia	2,085,824
Formaldehyde	288,412
Methanol	122,611
Sulfuric Acid	104,573
Hydrogen Sulfide	103,385
Toluene	87,945
Xylenes	79,177
Benzene	43,308
Hexane	39,646
Hydrogen Chloride	21,450

Source: CARB, CEIDARS database for 2009-2012, average annual routine TAC emissions

Add-on pollution control technologies which have been previously analyzed for hazards include carbon adsorption, incineration, post-combustion flue-gas treatment, SCR and selective non-catalytic reduction (SNCR), wet gas and dry gas scrubbers (LoTOx^{TM} with WGS, and UltraCat^{TM} with DGS), baghouses and supplemental filters, and electrostatic precipitators. The use of add-on pollution control equipment may concentrate or utilize hazardous materials. A malfunction or accident when using add-on pollution control equipment could potentially expose people to hazardous materials, explosions, or fires. The South Coast AQMD has determined that the transport, use, and storage of ammonia, both aqueous and anhydrous, (used in SCR and SNCR systems) may have significant hazard impacts in the event of an accidental release. Further analyses have indicated that the use of aqueous ammonia (in lieu of anhydrous ammonia) can usually reduce the hazards associated with ammonia use in SCR and SNCR systems to less than significant.

In addition, in response to a request by U.S. EPA, all refineries active during 2010 measured air emissions from each process and emission point for a specified time period and submitted the data to U.S. EPA. Analysis of this data resulted in the requirement for refineries to continue measuring a list of routinely emitted chemicals for each process. From these emissions inventories, OEHHA was able to identify the most commonly occurring processes in California refineries and their reported chemical emissions. Since some refinery processes are associated with a particular chemical profile, such information can be used to help anticipate the types of chemicals that may be released during a refinery accident and characterize the potential health effects of chemical exposure. Thus, consideration of common processes and characteristic emissions, in addition to knowledge of health guidance values and emergency exposure levels, can be used to help make judgements about air monitoring.[61]

Table 3.3-8 displays a list of most common chemicals and pollutants associated with typical refinery processes in California for 2010 as provided by U.S. EPA. It is important to note that the contents in Table 3.3-8 are not intended to be a complete list of all refinery processes or chemicals emitted from each process.

Table 3.3-8
Common Chemicals/Pollutants from Typical Refinery Process Units

Chemical / Pollutant Name	Typical Refinery Processes								
	Alkylation	Boiler	Cogen	Coker	Crude Unit	FCCU	Heater	SRU/ TGUs	Thermal Oxidizer
Ammonia	X	X	X	X	X	X	X	X	X
Benzene	X	X	X	X	X	X	X	X	X
Chrome-VI		X	X	X	X	X	X		X
Hydrogen Cyanide	X		X	X	X	X			X
Hydrogen Fluoride	X			X	X			X	
Hydrogen Sulfide	X	X	X	X	X	X	X	X	X
Lead		X	X	X	X	X	X		X
NOx		X	X	X	X	X	X	X	X
Selenium		X	X	X	X	X	X		X
Sulfur Dioxide		X	X	X	X	X	X	X	X
Vanadium Pentoxide		X	X	X	X	X	X		X
Vinyl Chloride								X	

Source: U.S. EPA, 2010.

For the proposed project, the following combustion equipment categories at refineries will be subject to the BARCT limits in PR 1109.1: 1) boilers; 2) gas turbines; 3) ground level flares; 4) fluidized catalytic cracking units; 5) petroleum coke calciners; 6) process heaters; 7) sulfur recover

[61] OEHHA, Analysis of Refinery Chemical Emissions and Health Effects, March 2019. https://oehha.ca.gov/media/downloads/faqs/refinerychemicalsreport032019.pdf (Accessed November 9, 2020).

units/tail gas treating units; 8) SMR heaters; 9) SMR heaters with gas turbine; 10) sulfuric acid furnaces; and 11) vapor incinerators.

In addition, the following air pollution control devices are expected to be employed to reduce NOx emissions from these combustion equipment categories and these devices require the use of the chemicals: SCRs (ammonia and fresh catalyst such a vanadium pentoxide), LoTOx™ with a WGS (soda ash or sodium hydroxide, depending on the type of equipment category), LoTOx™ without a WGS (oxygen), and UltraCat™ with DGS (ammonia and hydrated lime). In lieu of installing these air pollution control devices, facilities may opt to replace existing burners with ULNBs, and doing so would not require the use of any chemicals. Of the chemicals and pollutants listed in Table 3.3-8, only ammonia and vanadium pentoxide are used in the NOx control equipment that may be utilized if the proposed project is implemented while the remainder are not germane to the proposed project and are not discussed further in this SEA.

The following chemicals are specifically associated with operating the aforementioned air pollution control equipment that may be employed as a result of implementing the proposed project..

Ammonia

At room temperature, ammonia is a colorless gas that is typically found in the form of water vapor or particulates; it is corrosive at high concentrations. Ammonia odor is pungent and irritating, and therefore provides precautionary warning of its presence in most cases. However, after prolonged exposure to this chemical, it is more difficult to detect due to olfactory fatigue or adaptation.

Ammonia is the primary hazardous chemical identified with the use of SCR systems. Ammonia, though not a carcinogen, can have chronic and acute health impacts. Therefore, a potential increase in the use of ammonia may increase the current existing risk setting associated with deliveries (e.g., truck and road accidents) and onsite or offsite spills for each facility that currently uses or will begin to use ammonia. Exposure to a toxic gas cloud is the potential hazard associated with this type of control equipment. A toxic gas cloud is the release of a volatile chemical such as anhydrous ammonia that could form a cloud that migrates off-site, thus exposing individuals. Anhydrous ammonia is heavier than air such that when released into the atmosphere, it would form a cloud at ground level rather than be dispersed. "Worst-case" conditions tend to arise when very low wind speeds coincide with the accidental release, which can allow the chemicals to accumulate rather than disperse. Though there are facilities that may be affected by the 2016 AQMP control measures that are currently permitted to use anhydrous ammonia, for any new construction, however, current South Coast AQMD policy no longer allows the use of anhydrous ammonia. Instead, to minimize the hazards associated with ammonia used in the SCR or SNCR process, aqueous ammonia, 19 percent by volume, is typically required as a permit condition associated with the installation of SCR or SNCR equipment for the following reasons: 1) 19 percent aqueous ammonia does not travel as a dense gas like anhydrous ammonia; and 2) 19 percent aqueous ammonia is not on any acutely hazardous materials lists unlike anhydrous ammonia or aqueous ammonia at higher percentages. Also, if released, aqueous ammonia is likely to pool in liquid form and would be captured in a surrounding berm. As such, the release impacts of an aqueous ammonia release are not as great as anhydrous ammonia release.

Acute inhalation of ammonia may lead to corrosive injury to the skin and mucus membranes of the eyes, lungs, and gastrointestinal tract. Exposure to very high concentrations may result in eye redness and lacrimation (tearing), nose and throat irritation, cough, choking sensation, dyspnea (labored breathing or shortness of breath), lung damage, or death. Fatalities from ammonia exposure are most commonly caused by pulmonary edema (fluid accumulation in the lung). People with asthma and other respiratory conditions such as cardiopulmonary disease or with no tolerance developed from recent exposure may be more sensitive to the toxic effects of ammonia.

Chronic exposure to ammonia may impact pulmonary function tests or lead to subjective symptomatology in workers. Chronic cough, asthma, lung fibrosis, and chronic irritation of the eye membranes and skin have also been reported. The most sensitive endpoints of chronic ammonia exposure are decreased pulmonary function, and eye, skin, and respiratory irritation, which were reported in an occupational inhalation study at a concentration of 6.5 mg/m3.

Ammonia has been categorized as a slight fire hazard by the National Fire Protection Association with a lower explosive limit (LEL) equal to 15 percent, but this hazard is increased in the presence of oil or other combustible materials. The U.S. EPA characterizes ammonia as an extremely hazardous substance, and vapors may form an explosive mixture with air. OSHA regulations require employees of facilities where ammonia is used to be trained in the safe use of ammonia (see 29 CFR 1910.120). Facilities that handle over 10,000 pounds of anhydrous ammonia, or more than 20,000 pounds of ammonia in an aqueous solution of 20 percent ammonia or greater must prepare a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases. The CalARP threshold is more stringent at 500 pounds of anhydrous ammonia and facilities are evaluated for accident risk, and a determination is made whether an RMP is required.

<u>Selective Catalysts – Vanadium Pentoxide</u>
SCR catalysts typically contain heavy metal oxides such as vanadium and/or titanium, thus creating a potential human health and environmental risk related to the handling and disposal of spent catalyst. Vanadium pentoxide, the most commonly used SCR catalyst, is on the U.S. EPA’s list of Extremely Hazardous Materials. The quantity of waste associated with SCR is large, although the actual amount of active material in the catalyst bed is relatively small. This requires the use of licensed transport and disposal facilities and compliance with Resource Conservation and Recovery Act regulations. Facilities may face added costs by having to dispose of these materials out of state due to a lack of licensed disposal facilities that will handle these materials. This responsibility may not be borne by the plant since catalyst suppliers often collect and recycle spent catalyst as part of their contract.[62]

<u>Sodium Hydroxide</u>
Caustic made from sodium hydroxide (NaOH) is a common chemical used at refineries for use in caustic scrubbers and the production of biodiesel. Sodium hydroxide is an acutely hazardous substance but it is not classified as a carcinogen, Located on the SDS for NaOH (50 percent by weight), the hazards ratings are as follows: health is rated 3 (highly hazardous),

[62] U.S. Department of Energy, National Energy Technology Laboratory, Nitrogen Oxides. https://netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/nitrogen-oxides

flammability is rated 0 (none) and reactivity is rated 1 (slightly hazardous). Since NaOH is not a flammable compound, it is not known to have the potential to cause heat-related hazard impacts such as fires, explosions, boiling liquid – expanding vapor explosion (BLEVE).

A sodium hydroxide spill would not be expected to generate a vapor cloud, and hazards would be limited to the spilled material.[63] The presence of sodium hydroxide in the environment does not always lead to bystander exposure. In order for sodium hydroxide to cause adverse health effects, a person must come into contact with it by breathing, ingesting, or skin contact. Breathing in sodium hydroxide causes irritation of eyes, nose and throat, cough, chest tightness, headache, fever and confusion. An accumulation of fluid in the lungs may occur and may take up 36 hours to develop. Ingestion causes immediate burning of the mouth and throat, breathing difficulty, drooling, difficulty swallowing, stomach pain and vomiting. In serious cases there may be damage to heart, lungs, kidneys and blood. Dilute solutions may not be corrosive to the skin but can be irritating. Skin contact with stronger solutions can cause pain, burns, and ulcers. Eye contact causes pain, twitching of the eyelids, watering eyes, inflammation, sensitivity to light and burns.[64]

<u>Soda Ash</u>
Caustic can also be made from soda ash, instead of sodium hydroxide. Soda ash is the common name for sodium carbonate (Na2CO3), a non-toxic, non-cancerous, and non-hazardous substance. Located on the SDS for Na2CO3, the hazards ratings are as follows: health is rated 2 (moderate), flammability is rated 0 (none) and reactivity is rated 0 (none). Soda ash has a NFPA health rating 2 because it is corrosive and may be harmful if inhaled and may cause skin irritation and workers handling soda ash will need to take the necessary precautions when dealing with this substance.

<u>Hydrated Lime</u>
Hydrated lime, also known as calcium hydroxide ($Ca(OH)_2$) is a dry calcium- and sodium-based alkaline powdered sorbent that can be used to absorb NOx from the flue (outlet) gas stream. Hydrated lime is not flammable. Hydrated lime has a NFPA health rating 3 because it is very corrosive and may be harmful if inhaled and may cause skin irritation and workers handling Hydrated lime will need to take the necessary precautions when dealing with this substance.

<u>Oxygen</u>
Oxygen is an odorless, colorless, nonflammable gas that is stored in tanks or cylinders at high pressure. Oxygen is a non-toxic, non-cancerous, and non-hazardous substance. While no NFPA ratings have been assigned for health, flammability, or reactivity, the NFPA has assigned a special rating to oxygen, OXY, because it is considered an oxidizer that vigorously accelerates combustion. For example, some materials which are noncombustible in air will burn in the presence of an oxygen enriched atmosphere (greater than 23%). In addition, fire

[63] South Coast AQMD. Final Environmental Impact Report for Conoco Phillips Los Angeles Refinery – PM10 and NOx Reduction Projects, certified June 12, 2007. Main webpage: http://www.aqmd.gov/home/research/documents-reports/lead-agency-permit-projects/permit-project-documents---year-2007/feir-for-conocophillips-pm10-and-nox-reduction; and Chapter 4: http://www.aqmd.gov/docs/default-source/ceqa/documents/permit-projects/2007/conoco-phillips/ch4.pdf.

[64] Public Health England. Sodium Hydroxide General Information. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/769776/Sodium_Hydroxide_PHE_general_information_070119.pdf

resistant clothing may burn and offer no protection in oxygen rich atmospheres. Oxygen may form explosive compounds when exposed to combustible materials or oil, grease, and other hydrocarbon materials. Pressure in a container can build up due to heat and it may rupture if pressure relief devices should fail to function. Upon exposure to intense heat or flame cylinder will vent rapidly and/or rupture violently. Most storage tanks and cylinders are designed to vent contents when exposed to elevated temperatures.

SUBCHAPTER 3.4

HYDROLOGY

Regulatory Background

Hydrology

Water Demand and Forecasts

Water Supply

Water Conservation

3.4 HYDROLOGY

This subchapter describes existing regulatory settings relative to hydrology including water supply, water demand, and drought trends within California and within the Los Angeles County portion of the South Coast AQMD.

3.4.1 Regulatory Background

Water resources are regulated by an overlapping network of local, state, and federal laws and regulations. Potable water supply is managed through the following agencies and water districts: the California Department of Water Resources (DWR), the California Department of Health Services (DHS), the State Water Resources Control Board (SWRCB), the U.S. EPA, and the U.S. Bureau of Reclamation. Water right applications are processed through the SWRCB for properties claiming riparian rights. The DWR manages the State Water Project (SWP) and compiles planning information on water supply and water demand within the state. Applicable laws and regulations associated with hydrology are summarized in Table 3.4-1.

Table 3.4-1
Applicable Laws and Regulations for Hydrology

Applicable Regulations	Description
Federal	
Clean Water Act (CWA)	Administered primarily by U.S. EPA, the CWA pertains to water quality standards, state responsibilities, and discharges of waste to waters of the U.S. The U.S. EPA has delegated most of the administration of the CWA in California to the SWRCB.
State	
California Water Rights	The SWRCB administers water rights in California. SWRCB administers review, assessment, and approval of appropriative (or priority) surface water rights permits/licenses for diversion and storage for beneficial use. Riparian water rights apply to the land and allow diversion of natural flows for beneficial uses without a permit, but users must share the resources equitably during drought. Groundwater management planning is a function of local government. Groundwater use by overlying property owners is not formally regulated, except in cases where the groundwater basin supplies are limited and uses have been adjudicated, or through appropriative procedures for groundwater transfers.
Public Trust Doctrine	Body of common law that requires the State to consider additional terms and conditions when issuing or reconsidering appropriative water rights to balance the use of the water for many beneficial uses irrespective of the water rights that have been established. Public trust resources have traditionally included navigation, commerce, and fishing and have expanded over the years to include protection of fish and wildlife, and preservation goals for scientific study, scenic qualities, and open-space uses.

Table 3.4-1
Applicable Laws and Regulations for Hydrology

Applicable Regulations	Description
Porter-Cologne Water Quality Control Act (Water Code Sections 13000 et seq. and Title 23)	SWRCB is responsible for statewide water quality policy development and exercises the powers delegated to the State by the federal government under the CWA. Nine Regional Water Quality Control Boards (RWQCBs) adopt and implement water quality control plans (Basin Plans) which designate beneficial uses of surface waters and groundwater aquifers and establish numeric and narrative water quality objectives for beneficial use protection.
SB 1168, Statutes of 2014 Chapter 346, Pavley	This bill requires all groundwater basins designated as high- or medium-priority basins by the Department of Water Resources that are designated as basins subject to critical conditions of overdraft to be managed under a groundwater sustainability plan or coordinated groundwater sustainability plans by January 31, 2020, and requires all other groundwater basins designated as high- or medium-priority basins to be managed under a groundwater sustainability plan or coordinated groundwater sustainability plans by January 31, 2022. This bill would require a groundwater sustainability plan to be developed and implemented to meet the sustainability goal, established as prescribed, and would require the plan to include prescribed components.
AB 1739, Statutes of 2014, Dickinson, Chapter 347	This bill establishes groundwater reporting requirements for a person extracting groundwater in an area within a basin that is not within the management area of a groundwater sustainability agency or a probationary basin. The bill requires the reports to be submitted to State Water Resources Control Board or, in certain areas, to an entity designated as a local agency by State Water Resources Control Board.
SB 1319, Statutes of 2014, Chapter 348, Pavely	This bill allows State Water Resources Control Board to designate a groundwater basin as a probationary basin subject to sustainable groundwater management requirements. This bill also authorizes State Water Resources Control Board to develop an interim management plan in consultation with the Department of Water Resources under specified conditions.
1991 Water Recycling Act	The 1991 Water Recycling Act established water recycling as a priority in California and encourages municipal wastewater treatment districts to implement recycling programs to reduce local water demands
California Water Code Section 10608.20	This section of the California Water Code requires each supplier of urban water supplier to demonstrate the availability of current and projected water supplies by adopting an Urban Water Management Plan.
Local	

Table 3.4-1
Applicable Laws and Regulations for Hydrology

Applicable Regulations	Description
Water Agencies	Water agencies enter into contracts or agreements with the federal and State governments to protect the water supply and to ensure the lands within the agency have a dependable supply of suitable quality water to meet present and future needs. Local cities, counties and water districts may also provide guidance on CEQA projects regarding water resources. Many jurisdictions incorporate policies related to water resources in their municipal codes, development standards, storm water pollution prevention requirements, and other regulations. Also, as required by the California Water Code Section 10608.20, local suppliers are required to adopt Urban Water Management Plans for their jurisdictions.

3.4.2 Hydrology

3.4.2.1 Water Sources

Surface waters occur as streams, lakes, ponds, coastal waters, lagoons, estuaries, floodplains, dry lakes, desert washes, wetlands, and other collection sites. Water bodies modified or developed by man, including reservoirs and aqueducts, are also considered surface waters.

Surface water resources are very diverse throughout the state due to the high variance in tectonics, topography, geology/soils, climate, precipitation, and hydrologic conditions. Overall, California has the most diverse range of watershed conditions in the U.S., with varied climatic regimes ranging from Mediterranean climates with temperate rainforests in the north coast region to desert climates containing dry desert washes and dry lakes in the southern central region.

The average annual runoff for California is 71 million acre-feet. The state has more than 60 major stream drainages and more than 1,000 smaller but significant drainages that drain coastal mountains and inland mountainous areas. High snowpack levels and resultant spring snowmelt yield high surface runoff and peak discharge in the Sierra Nevada and Cascade Mountains that feed surface flows, fill reservoirs, and recharge groundwater.

Federal, state, and local engineered water projects, aqueducts, canals, and reservoirs serve as the primary conduits of surface water sources to areas that have limited surface water resources. Most of the surface water storage is transported for agricultural, urban, and rural residential needs to the San Francisco Bay Area and to cities and areas extending to southern coastal California. Surface water is also transported to southern inland areas, including Owens Valley, Imperial Valley, and Central Valley areas.

The DWR divided California into ten hydrologic regions corresponding to the state's major water drainage basins. The hydrologic regions define a river basin drainage area and are used as planning boundaries, which allows consistent tracking of water runoff, and the accounting of surface water and groundwater supplies (DWR, 2010).[65]

The Basin lies within the South Coast Hydrologic Region. The South Coast Hydrologic Region is California's most urbanized and populous region. More than half of the state's population resides in the region (about 19.6 million people or about 54 percent of the state's population), which covers 11,000 square miles or seven percent of the state's total land. The South Coast Hydrologic Region extends from the Pacific Ocean east to the Transverse and Peninsular Ranges, and from the Ventura-Santa Barbara County line south to the international border with Mexico and includes all of Orange County and portions of Ventura, Los Angeles, San Bernardino, Riverside, and San Diego counties (DWR, 2010).

Topographically, most of the South Coast Hydrologic Region is composed of several large, undulating coastal and interior plains. Several prominent mountain ranges comprise its northern and eastern boundaries and include the San Gabriel and San Bernardino mountains. Most of the region's rivers drain into the Pacific Ocean, and many terminate in lagoons or wetland areas that serve as important coastal habitat. Many river segments on the coastal plain, however, have been concrete-lined and in other ways modified for flood control operations (DWR, 2010).

There are 19 major rivers and watersheds in the South Coast Hydrologic Region. Many of these watersheds have densely urbanized lowlands with concrete-lined channels and dams controlling flood flows. The headwaters for many rivers, however, are within coastal mountain ranges and have remained largely undeveloped (DWR, 2010).

The cities of Ventura, Los Angeles, Long Beach, Santa Ana, San Bernardino, and Big Bear Lake are among the many urban areas in this section of the state, which contain moderate-sized mountains, inland valleys, and coastal plains. The Santa Clara, Los Angeles, San Gabriel, and Santa Ana rivers are among the area's hydrologic features. In addition to water sources within the South Coast Hydrologic Region, imported water makes up a major portion of the water used in the Basin. Water is brought into the South Coast Hydrologic Region from three major sources: the Sacramento-San Joaquin Delta (Delta), Colorado River, and Owens Valley/Mono Basin. Most lakes in this area are actually reservoirs, made to hold water coming from the SWP, the Los Angeles Aqueduct (LAA), and the Colorado River Aqueduct (CRA) including Castaic Lake, Lake Mathews, Lake Perris, Silverwood Lake, and Diamond Valley Lake. In addition to holding water, Lake Casitas, Big Bear Lake, and Morena Lake regulate local runoff.

3.4.2.2 Surface Water Hydrology

Surface water hydrology refers to surface water systems, including watersheds, floodplains, rivers, streams, lakes and reservoirs, and the inland Salton Sea. Surface waters occur as streams, lakes, ponds, coastal waters, lagoons, estuaries, floodplains, dry lakes, desert washes, wetlands, and other collection sites. Water bodies modified or developed by man, including reservoirs and aqueducts, are also considered surface waters.

[65] California Water Plan Update, 2009. Integrated Water Management. Bulletin 160-109, DWR, 2010.

Surface water resources are very diverse throughout the state due to the high variance in tectonics, topography, geology/soils, climate, precipitation, and hydrologic conditions. Overall, California has the most diverse range of watershed conditions in the U.S., with varied climatic regimes ranging from Mediterranean climates with temperate rainforests in the north coast region to desert climates containing dry desert washes and dry lakes in the southern central region.

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Watersheds

Watersheds refer to areas of land, or basin, in which all waterways drain to one specific outlet, or body of water, such as a river, lake, ocean, or wetland. Watersheds have topographical divisions such as ridges, hills or mountains. All precipitation that falls within a given watershed, or basin, eventually drains into the same body of water (SCAG, 2012).[66] There are 20 major watersheds within southern California region, all of which are outlined and shaped by the various topographic features of the region. Given the physiographic characteristics of the region, most of the watersheds are located along the Transverse and Peninsular Ranges, and only a small number are in the desert areas (Mojave and Colorado Desert) (SCAG, 2012). Figure 3.4-1 presents a map of the watersheds within the South Coast AQMD.

Rivers

Because the climate of Southern California is predominantly arid, many of the natural rivers and creeks are intermittent or ephemeral, drying up in the summer or flowing only after periods of precipitation. For example, annual rainfall amounts vary depending on elevation and proximity to the coast. Some waterways such as Ballona Creek and the Los Angeles River maintain a perennial flow due to agricultural irrigation and urban landscape watering (SCAG, 2012). Figure 3.4-2 presents a map of the major rivers within the district.

Major natural streams and rivers in the South Coast Hydrologic Region include the Ventura River, Santa Clara River, Los Angeles River, San Gabriel River, Santa Ana River, San Jacinto River, and upstream portions of the Santa Margarita River.

[66] Draft Program Environmental Impact Report for the 2012 – 2035 RTP/SCS. SCAG, 2012.

The Ventura River, located outside of the district, is fed by Lake Casitas on the western border of Ventura County and empties out into the ocean. It is the northern-most river system in Southern California, supporting a large number of sensitive aquatic species. Water quality decreases in the lower reaches due to urban and industrial impacts.

The Santa Clara River starts in Los Angeles County, flows through the center of Ventura County, and remains in a relatively natural state. Threats to water quality include increasing development in floodplain areas, flood control measures such as channeling, erosion, and loss of habitat.

The Los Angeles River is a highly disturbed system due to the flood control features along much of its length. Due to the high urbanization in the area around the Los Angeles River, runoff from industrial and commercial sources as well as illegal dumping contribute to reduce the channel's water quality.

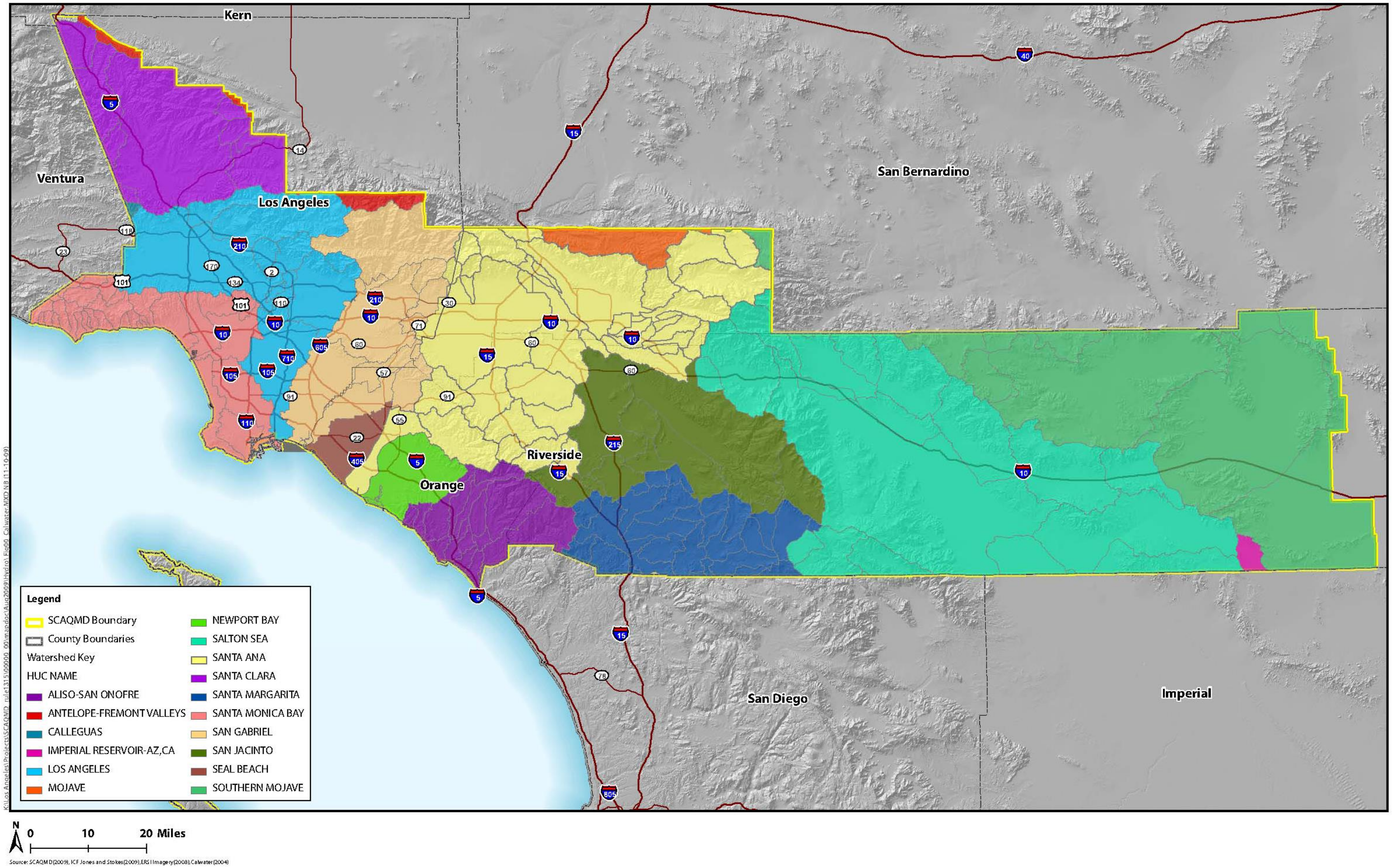

Figure 3.4-1
USGS Watersheds within the South Coast AQMD

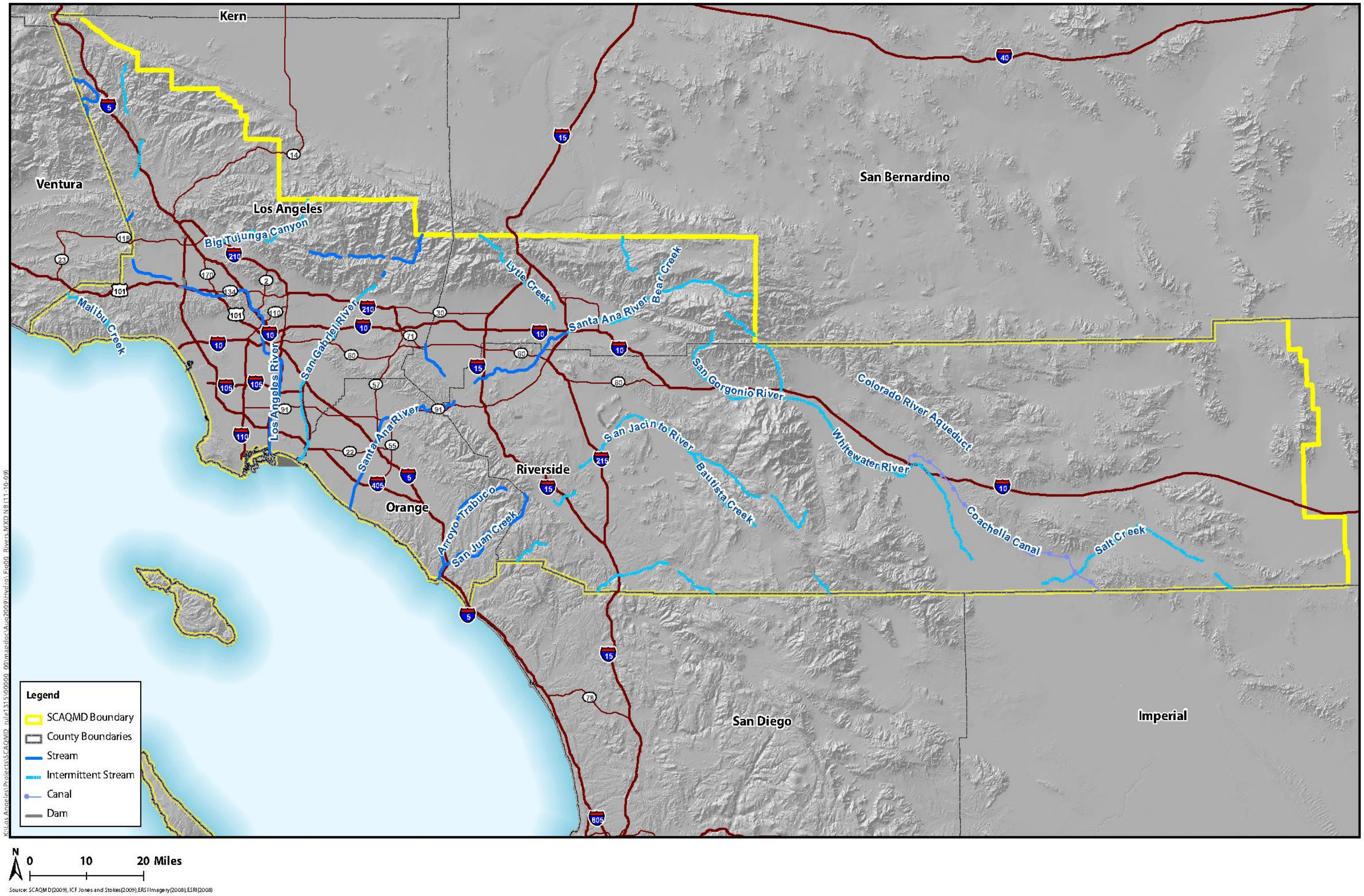

Figure 3.4-2
Rivers within the South Coast AQMD

The San Gabriel River is similarly altered with concrete flood control embankments and impacted by urban runoff.

The Santa Ana River drains the San Bernardino Mountains, cuts through the Santa Ana Mountains, and flows onto the Orange County coastal plain. Recent flood control projects along the river have established reinforced embankments for much of the river's path through urbanized Orange County.

The Santa Margarita River begins in Riverside County, draining portions of the San Jacinto Mountains and flowing to the ocean through northern San Diego County.

Lakes and Reservoirs

Since southern California is a semi-arid region, many of its lakes are drinking water reservoirs, created either through damming of rivers, or manually dug and constructed. Reservoirs also serve as flood control for downstream communities. Some of the most significant lakes, including reservoirs, in the Basin are Big Bear Lake, Lake Arrowhead, Lake Casitas, Castaic Lake, Pyramid Lake, Lake Elsinore, Diamond Valley Lake, and the Salton Sea (SCAG, 2012).

Big Bear Lake is a reservoir in San Bernardino County, in the San Bernardino Mountains. It was created by a granite dam in 1884, which was expanded in 1912, and holds back approximately 73,000 acre-feet[67] of water. The lake has no tributary inflow, and is replenished entirely by snowmelt. It provides water for the community of Big Bear, as well as nearby communities (SCAG, 2012).

Lake Arrowhead is also in San Bernardino County, at the center of an unincorporated community also called Lake Arrowhead. The lake is a man-made reservoir, with a capacity of approximately 48,000 acre-feet of water. In 1922, the dam at Lake Arrowhead was completed, with the intention of turning the area into a resort. It is now used for recreation and as a potable water source for the surrounding community (SCAG, 2012).

Lake Casitas is in Ventura County, and was formed by the Casitas Dam on the Coyote Creek just before it joins the Ventura River. The dam, completed in 1959, holds back nearly 255,000 acre-feet of water. The water is used for recreation, as well as drinking water and irrigation (SCAG, 2012).

Castaic Lake is on the Castaic Creek, and was formed by the completion of the Castaic Dam. The lake is in northwestern Los Angeles County. It is the terminus of the West Branch of the California Aqueduct, and holds over 323,000 acre-feet of water. Much of the water is distributed throughout northern Los Angeles County, though some is released into Castaic Lagoon, which feeds Castaic Creek. The creek is a tributary of the Santa Clara River (SCAG, 2012).

Pyramid Lake is just above Castaic Lake, and water flows from Pyramid into Castaic through a pipeline, generating electricity during the day. At night, when electricity demand and prices

[67] One acre-foot of water is equivalent to 325,851 gallons.

are low, water is pumped back up into Pyramid Lake. Pyramid Lake is on Piru Creek, and holds 180,000 acre-feet of water (SCAG, 2012).

Lake Elsinore is in the City of Lake Elsinore, in Riverside County. While the lake has been dried up and subsequently replenished throughout the last century, it now manages to maintain a consistent water level with outflow piped into the Temescal Canyon Wash (SCAG, 2012).

Diamond Valley Lake is Southern California's newest and largest reservoir. Located in Riverside County, it was a project of Metropolitan Water District (MWD) to expand surface storage capacity in the region. A total of three dams were required to create the lake. Completed in 1999, it was full by 2002, holding 800,000 acre-feet of water, effectively doubling MWD's surface water storage in the region. The lake is connected to the existing water infrastructure of the SWP. The lake is situated at approximately 1,500 feet above sea level, well above most of the users of the lake's water which enables the lake to also provide hydroelectric power, as water flows through the lowest dam (SCAG, 2012).

The Salton Sea is California's largest lake, nearly 400 square miles in size. The lake is over 200 feet below sea level, and has flooded and evaporated many times over, when the Colorado overtops its banks during extreme flood years. This cycle of flooding and evaporation has re-created the Salton Sea several times during the last thousand years and has resulted in high levels of salinity. The lake's most recent formation occurred in 1905 after an irrigation canal was breached and the Colorado River flowed into the basin for 18 months, creating the current lake (SCAG, 2012).

The principle inflow to the Salton Sea is from agricultural drainage, which is high in dissolved salts; approximately four million tons of dissolved salts flow into the Salton Sea every year. The evaporation of the Salton Sea's water, plus the addition of highly saline water from agriculture, has created one of the saltiest bodies of water in the world. The Sea has been a highly successful fishery and is a habitat and migratory stopping and breeding area for 380 different bird species; however, the high, and ever-increasing, salinity of the Sea has resulted in declining fish populations that inhabit it, resulting in declining local and migratory bird that rely on the fish as a food source (SCAG, 2012).

The major surface waters in this section are presented in Table 3.4-2.

Table 3.4-2
Major Surface Waters

Wetlands	Rivers, Creeks, and Streams	Lakes and Reservoirs
	Los Angeles Basin	
Ventura River Estuary Santa Clara River Estuary McGrath Lake Ormond Beach Wetlands Mugu Lagoon Trancas Lagoon Topanga Lagoon Los Cerritos Wetlands Ballona Lagoon Los Angeles River Ballona Wetlands	Sespe Creek Piru Creek Ventura River Santa Clara River Los Angeles River Big Tujunga Canyon San Gabriel River	Lake Casitas Lake Piru Pyramid Lake Castaic Lake Bouquet Reservoir Los Angeles Reservoir Chatsworth Reservoir Sepulveda Reservoir Hansen Reservoir San Gabriel Reservoir Morris Reservoir Whittier Narrows Reservoir Santa Fe Reservoir
	Lahontan Basin	
	Mojave River Amargosa River	Silver Lake Silverwood Lake Mojave River Reservoir Lake Arrowhead Soda Lake
	Colorado River Basin	
	Colorado River Whitewater River Alamo River New River	Lake Havasu Gene Wash Reservoir Copper Basin Reservoir Salton Sea Lake Cahuilla
	Santa Ana Basin	
Hellman Ranch Wetlands Anaheim Bay Bolsa Chica Wetlands Huntington Wetlands Santa Ana River Laguna Lakes San Juan Creek Upper Newport Bay San Joaquin Marsh Prado Wetlands	Santa Ana River San Jacinto River	Prado Reservoir Big Bear Lake Lake Perris Lake Matthews Lake Elsinore Vail Lake Lake Skinner Lake Hemet

Source: Draft Program EIR for the 2012-2035 RTP/SCS; SCAG; December 2011, p. 3.13-13.

3.4.2.3 Groundwater Hydrology

The majority of runoff from snowmelt and rainfall flows down mountain streams into low gradient valleys and either percolates into the ground or is discharged to the sea. This percolating flow is stored in alluvial groundwater basins that cover approximately 40 percent of the geographic extent of the state. Groundwater recharge occurs more readily in areas underlain by coarse sediments, primarily in mountain base alluvial fan settings. As a result, most of California's groundwater basins are located in broad alluvial valleys flanking mountain ranges, such as the Cascade Range, Coast Ranges, Transverse Ranges, and the Sierra Nevada.

There are 250 major groundwater basins that serve approximately 30 percent of California's urban, agricultural, and industrial water needs, especially in southern portion of San Francisco Bay, the Central Valley, greater Los Angeles area, and inland desert areas where surface water is limited. On average, more than 15 million acre-feet of groundwater are extracted each year in the state, of which more than 50 percent is extracted from 36 groundwater basins in the Central Valley.

Groundwater is the part of the hydrologic cycle representing underground water sources. Groundwater is present in many forms: in reservoirs, both natural and constructed; in underground streams; and, in the vast movement of water in and through sand, clay, and rock beneath the earth's surface. The place where groundwater comes closest to the surface is called the water table, which in some areas may be very deep, and in others may be right at the surface. Groundwater hydrology is, therefore, connected to surface water hydrology, and cannot be treated as a separate system. One example of how groundwater hydrology can directly impact surface water hydrology is when surface streams are partly filled by groundwater. When that groundwater is pumped out and removed from the system, the stream levels will fall, or even dry up entirely, even though no water was removed from the stream itself (SCAG, 2012).

Groundwater represents most of the Basin's fresh water supply, making up approximately 30 percent of total water use, depending on precipitation levels. Groundwater basins are replenished mainly through infiltration – precipitation soaking into the ground and making its way into the groundwater. Two threats to the function of this system are increases in impervious surface and overdraft (SCAG, 2012).

Impervious surface decreases the area available for groundwater recharge, as precipitation runoff flows off of streets, buildings, and parking lots directly into storm sewers, and straight into either river channels or into the ocean. This prevents the natural recharge of groundwater, effectively removing groundwater from the system without any pumping. Impervious surface also deteriorates the quality of the water, as it moves over streets and buildings, gathering pollutants and trash before entering streams, rivers, and the ocean (SCAG, 2012).

To prevent seawater intrusion in coastal basins in Orange County, recycled water is injected into the ground to form a mound of groundwater between the coast and the main groundwater basin. In Los Angeles County, imported and recycled water is injected to maintain a seawater intrusion barrier (SCAG, 2012).

VOCs and other non-organic contaminants such as perchlorates have created groundwater impairments in industrialized portions of the San Gabriel and San Fernando Valley groundwater basins, where some locations have been declared federal Superfund sites. Subsequently, perchlorate contamination was found in the San Gabriel Valley, and is being removed. The USEPA continues to oversee installation of a groundwater cleanup system, components of which were installed beneath the cities of La Puente and Industry in 2006. Similar problems exist in the Bunker Hills sub-basin of the Upper Santa Ana Valley groundwater basin. Perchlorate contamination has also been found in wells in the cities of Rialto, Colton, and Fontana in San Bernardino County. The presence of contamination in the source water does not necessarily require the closure of a groundwater well. Water systems can implement water treatment accompanied by monthly monitoring for contaminants and/or may blend the problematic water with other "cleaner" water in order to reduce the concentration of the contaminants of concern in the water that is ultimately to be delivered to the end-users (SCAG, 2012). For these reasons, groundwater continues to be used as the predominant source of water supply in these areas (SCAG, 2012).

3.4.3 Water Demand and Forecasts

Estimating total water use in the district is difficult because the boundaries of supplemental water purveyors' service areas bear little relation to the boundaries of the district and there are dozens of individual water retailers within the district. Water demand in California can generally be divided between urban, agricultural, and environmental uses. In southern California, approximately 75 percent of potable water is provided from imported sources. Annual water demand fluctuates in relation to available supplies. During prolonged periods of drought, water demand can be reduced significantly through conservation measures, while in years of above average rainfall demand for imported water usually declines. In 2000, a 'normal' year in terms of annual precipitation, the demand for water in the State was between approximately 82 and 83 million acre-feet. Of this total, southern California accounted for approximately 9.8 million acre-feet (SCAG, 2012).

The increase in California's water demand is due primarily to the increase in population. By employing a multiple future scenario analysis, the California Water Plan Update 2018 (DWR, 2018) provides a growth range for future annual water demand. According to the California Water Plan Update 2018, statewide future annual water demands range from an increase of fewer than 1 million acre-feet to an increase of about 6 million acre-feet under the Expansive Growth scenario by year 2050. If southern California maintains its share of 12 percent of the state's water demand, the region could be expected to require an additional 500,000 acre-feet by 2030 (SCAG, 2012).

On June 4, 2008, Governor Arnold Schwarzenegger issued Executive Order S-06-08 and declared an official drought for California.[68] Further, California Water Code Section 71460 et seq. states that a water district may restrict the use of water during any emergency caused by drought, or other threatened or existing water shortage, and may prohibit the use of water during such periods for any purpose other than household uses or such other restricted uses as determined to be necessary. The water district may also prohibit the use of water during such periods for specific uses which it finds to be nonessential. On February 27, 2009, Governor Schwarzenegger proclaimed a state of emergency regarding the drought and the availability and future sustainability of California's water resources.[69] The proclamation directed all state government agencies to utilize their resources, implement a state emergency plan and provide assistance for people, communities and businesses

[68] Executive Order S-06-08; https://www.smgov.net/uploadedFiles/Departments/OSE/Task_Force_on_the_Environment/TFE_2008/Attachment%207_CA_DroughtNotification2008.pdf?n=8209

[69] State of Emergency – Water Shortage; https://www.smgov.net/departments/council/agendas/2009/20090512/s2009051208-A-3.htm

impacted by the drought. The proclamation further requested that all urban water users immediately increase their water conservation activities in an effort to reduce their individual water use by 20 percent.

Following substantial increases in statewide rainfall and mountain snowpack, on March 30, 2011, Governor Brown officially rescinded Executive Order S-06-08, issued on June 4, 2008 and ended the States of Emergency regarding the drought on June 12, 2008, and on February 27, 2009. The fourth snow survey of the season was conducted by the DWR and found that water content in California's mountain snowpack was 165 percent of the April 1 full season average. At that time, a majority of the state's major reservoirs were also above normal storage levels. Based on this data, DWR estimated it would be able to deliver 70 percent of requested SWP water for 2011.

In 2012, an uptick in water use occurred due to a dry winter and a below-normal snowpack. Statewide hydrologic conditions at the end of June 2012 showed 80 percent of average precipitation to date; runoff at 65 percent of average to date; and reservoir storage at 100 percent of average for the date. However, impacts of drought are typically felt first by those most reliant on annual rainfall such as small water systems lacking a reliable source, rural residents relying on wells in low-yield rock formations, or ranchers engaged in dryland grazing. As of mid-July 2012, 75-percent of California's pasture and range land was reported to be experiencing "poor" or "very poor" water conditions. Over half of the contiguous U.S. was experiencing drought conditions, the largest percentage of the nation experiencing drought conditions in the 12-year record of the U.S. Drought Monitor.

This trend in water shortfall has continued throughout California. In May 2013, Governor Brown issued Executive Order B-21-13 to direct state water officials to expedite the review and processing of voluntary transfers of water and water rights.[70] In December 2013, the Governor formed a Drought Task Force to review expected water allocations, California's preparedness for water scarcity and whether conditions merit a drought declaration. In January 2014, the year 2013 was recorded as the driest year in California's history with California's river and reservoirs below their record lows as well as the snowpack's statewide water content at about 20 percent of normal average. Subsequently, on January 17, 2014, Governor Brown proclaimed a State of Emergency and directed state officials to take all necessary actions to prepare for drought conditions.[71] The proclamation directs state officials to assist farmers and communities that are economically impacted by dry conditions and to ensure the state can respond if there are drinking water shortages. The proclamation also directs state agencies to use less water and hire more firefighters and to initiate a greatly expanded water conservation public awareness campaign. Lastly, the proclamation gives state water officials more flexibility to manage supply throughout California under drought conditions. In response to Governor Brown's proclamation, the DWR took actions to conserve the state's water resources by supplying everyone (e.g., farmers, fish, and people throughout California's cities and towns) with less water.[72] It is important to note that almost all

[70] Governor Brown Issues Executive Order to Streamline Approvals for Water Transfers to Protect California's Farms; https://www.ca.gov/archive/gov39/2013/05/20/news18048/index.html

[71] Governor Brown Declares Drought State of Emergency, January 17, 2014. https://www.ca.gov/archive/gov39/2014/01/17/news18368/index.html

[72] DWR Drops State Water Project Allocation to Zero, Seeks to Preserve Remaining Supplies. DWR, 2014. https://www.lvmwd.com/home/showpublisheddocument?id=3860

areas served by the SWP have other sources of water, such as groundwater, local reservoirs, and other supplies.

On March 1, 2014, Governor Brown signed a drought relief package[73] which provided $687.4 million to support drought relief, including money for housing and food for workers directly impacted by the drought, bond funds for projects to help local communities more efficiently capture and manage water and funding for securing emergency drinking water supplies for drought-impacted communities. In addition, the legislation increased funding for state and local conservation corps to assist communities with efficiency upgrades and reduce fire fuels in fire risk areas, and includes $1 million for the Save Our Water public awareness campaign to enhance its mission to inform Californians how they can do their part to conserve water. In addition, the legislation required the California Department of Public Health (DPH) to adopt new groundwater replenishment regulations by July 1, 2014, and for the State Water Resources Control Board and the DPH to work on additional measures to allow for the use of recycled water and storm water capture for increasing water supply availability. The legislation also made statutory changes to: 1) ensure existing water rights laws are followed; 2) include streamlined authority to enforce water rights laws; and, 3) increase penalties for illegally diverting water during drought conditions. The legislation also provided the California Department of Housing and Community Development with the greatest flexibility to maximize migrant housing units.[74]

As of May 29, 2014, the SWRCB issued a curtailment order for 2,648 water agencies and users (e.g., farms, cities and other property owners with so-called "junior" water rights, or those issued by the state after 1914, in the Sacramento River and its tributaries in the Sacramento Valley) to stop pumping water from the American, Feather and Yuba rivers as well as dozens of small streams.[75] Rain and snow from February and March storms have allowed the DWR to increase water contract allocations for SWP deliveries from zero to five percent. Precipitation from these recent storms also eliminated the need for rock barriers to be constructed in the Delta to prevent saltwater intrusion. Additional flexibility in salinity control requirements is being sought as an alternative to the Delta rock barriers that is less harmful for fish, wildlife, and other Delta water users. The Department of Fish and Wildlife (DFW) announced that it will fast-track actions to manage and reduce the drought's impact on fish.

On April 25, 2014, Governor Brown proclaimed a second State of Emergency, which waived compliance with CEQA and the state water code for a number of actions, including water transfers, wastewater treatment projects, habitat improvements for winter-run Chinook salmon imperiled by the drought and curtailment of water rights. Furthermore, the order also suspended competitive bidding requirements for drought-related projects undertaken by a number of state agencies, including the DWR, DFW, and DPH. The proclamation closed a loophole that previously allowed homeowner associations to require residents to water lawns, even if the watering conflicted with local water agency rules, and to fine them if they did not comply. On September 16, 2014, Governor Brown signed legislation for California to begin regulating groundwater, a historic

[73] Governor Jerry Brown Signs Drought Relief Package, 2014. https://www.latimes.com/local/lanow/la-me-ln-brown-signs-drought-relief-package-20140301-story.html
[74] Governor Brown, Legislative Leaders Announce Emergency Drought Legislation, 2014. https://www.ca.gov/archive/gov39/2014/02/19/news18415/index.html
[75] California Orders Thousands of Sacramento Valley Water Users To Stop Pumping From Streams, 2014. https://www.sacbee.com/news/local/article2600034.html

change that could lead to restrictions on pumping in some areas to prevent aquifers from dwindling and wells from running dry. The package of three laws put local agencies in charge of managing groundwater supplies, while giving the state new authority to step in when necessary to stabilize declining water tables. The new laws went into effect on January 1, 2015 and target areas where groundwater is being depleted faster than it is being replenished. Local agencies will then have until 2020 or 2022, depending on the severity of the situation, to develop plans for managing groundwater.[76]

Water districts, in response to the drought, have also taken actions throughout the state such as: 1) asking for voluntary reductions; 2) imposing mandatory restrictions or declaring a local emergency; 3) imposing agricultural rationing; 4) imposing drought rates, surcharges and fines; 5) limiting new development and requiring water efficient landscaping; 6) implementing a conservation campaign; 7) stopping water pumping from various streams; and, 8) adjusting water contract allocations. In addition, water shortages have prompted cities to begin infrastructure improvements to secure future water supplies.

On April 7, 2017, Governor Brown issued Executive Order B-40-17 which lifts the drought emergency in California apart from four counites in Central California. The executive order retains the prohibition on wasteful practices and advances measures pertaining to water conservations practices. The order also rescinds two emergency proclamations from both January and April of 2014 and four drought-related executive orders issued in 2014 and 2015.[77]

On April 21, 2021, after California entered its second consecutive year of dry conditions, Governor Newsom proclaimed a State of Emergency in the Mendocino and Sonoma counties due to drought conditions in the Russian River Watershed.[78] State agencies were directed to partner with regional and local government agencies to promote the Save Our Water conservation campaign and identify areas that may require coordinated state and local action, assist Native American tribes, and accelerate funding for water projects. Specific directives were also issued for according to each state agency such as the Department of Water Resources to encourage reporting of water shortages, the Water Board to modify requirements for reservoir releases or division limitations, the Department of Fish and Wildlife to maintain habitats for vulnerable species, and the Department of Food and Agriculture to analyze economic impacts from the drought). CEQA requirements in Public Resources Code Division 12 Section 21000 et seq. and regulations adopted pursuant to Division 12 , and provisions of the Government Code and the Public Contract Code were suspended in the counties of Mendocino and Sonoma for the purposes of addressing the drought. On May 10, 2021, Governor Newsom expanded the State of Emergency to the Klamath River, Sacramento-San Joaquin Delta, and Tulare Lake Watershed Counties.[79] Additional directives were issued including the suspension of Water Code Section 1726(d) for written notice and newspaper publication provided notices are posted on the website and provided electronically, Water Code Section 1726(f) for a 30-day comment period provided that a 15-day comment period is afforded

[76] Governor Jerry Brown Signs Landmark Groundwater Legislation, 2014. http://www.desertsun.com/story/news/environment/2014/09/16/california-groundwater-legislation/15725863/

[77] Executive Order B-40-17. https://www.ca.gov/archive/gov39/wp-content/uploads/2017/09/4.7.17_Attested_Exec_Order_B-40-17.pdf

[78] https://www.gov.ca.gov/wp-content/uploads/2021/04/4.21.21-Emergency-Proclamation-1.pdf

[79] https://www.gov.ca.gov/wp-content/uploads/2021/05/5.10.2021-Drought-Proclamation.pdf

instead, and Government Code Sections 7405 and 11546.7 pertaining to the posting and dissemination of information.

On July 8, 2021, Governor Newsom issued Executive Order N-10-21 which: 1) called on Californians to voluntarily reduce their water use by 15 percent via irrigating landscapes more efficiently, running dishwasher and washing machines only when full, finding and fixing leaks, installing water-efficient showerheads and taking shorter shower, and using a shut-off nozzle on hoses and taking cars to commercial car washes which use recycled water; 2) directed state agencies to promote the Save Our Water conservation campaign; and 3) directed the Department of Water Resources to monitor hydrologic conditions and the Water Board to monitor progress on voluntary conservation.[80]

3.4.3.1 Water Suppliers

Southern California is served by many water suppliers, both retail and wholesale with Metropolitan Water District (MWD) being the largest. Created by the California legislature in 1931, MWD serves the urbanized coastal plain from Ventura in the north to the Mexican border in the south to parts of the rapidly urbanizing counties of San Bernardino and Riverside in the east. MWD provides water to about 90 percent of the urban population of southern California. MWD is comprised of 26 member agencies, with 12 supplying wholesale water to retail agencies and other wholesalers. The remaining 14 agencies are individual cities which directly supply water to their residents.

MWD monitors demographics in its service area since water demand is heavily influenced by population size, geographical distribution, variation in precipitation levels, and water conservation practices. In 1990, the population of MWD's service area was approximately 15 million people. By 2015, it had reached an estimated 18.7 million, representing about 50 percent of the state's population. The MWD service area is estimated to reach an estimated population of 21.3 million in 2025, and 22.5 million by 2035 (MWD, 2015). Average per capita water usage generally ranges from 170 to 285 gallons per day (SCAG, 2012).

Actual retail water demands within MWD's service area have increased from 2.9 million acre-feet in 1983 to 4.7 million acre-feet in 2007. Since the peak retail demand in 2007, a decrease in demand was observed during the economic recession of 2008-2012. Starting in 2012, the severe drought in California led to a massive conservation campaign and water use restriction by the State, Metropolitan, and local water agencies resulting in a decrease in demand in 2015.[81]

In 2020, about 96 percent of the retail demands were used for municipal and industrial purposes (M&I), and 4 percent for agricultural purposes. The relative share of agricultural water use has declined due to urbanization and market factors, including the price of water. Agricultural water use accounted for 19 percent of total regional water demand in 1970, 12 percent in 1980, 10 percent in 1990, and 4 percent in 2010 (MWD, 2021).

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[80] Executive Department, State of California, Executive Order N-10-21, July 8, 20201. https://www.gov.ca.gov/wp-content/uploads/2021/07/7.8.21-Conservation-EO-N-10-21.pdf

[81] 2015 Urban Water Management Plan (MWD, 2015).

3.4.3.2 Water Uses

While most land use in the region is urban, other land uses include national forest and a small percentage of irrigated crop acreage (DWR, 1998).[82] The South Coast Hydrologic Region is the most populous and urbanized region in California. In some portions of the region, water users consume more water than is locally available, which has resulted in an overdraft of groundwater resources and increasing dependence on imported water supplies. The distribution of water uses, however, varies dramatically across the South Coast's planning areas. As a result of recent droughts, South Coast water users have generally become more water efficient. Municipal water agencies are engaged in aggressive water conservation and efficiency programs to reduce per capita water demand. As a result of changes in plumbing codes, energy and water efficiency innovations in appliances, and trends toward more water efficient landscaping practices, urban water demand has become more efficient (DWR, 2010).

For the South Coast region, urban water uses are the largest component of the developed water supply, while agricultural water use is a smaller but significant portion of the total. Imported water supplies and groundwater are the major components of the water supply for this region, with minor supplies from local surface waters and recycled water (DWR, 2010).

Of the total water supply to the region, more than half is either used by native vegetation; evaporates to the atmosphere; provides some of the water for agricultural crops and managed wetlands (effective precipitation); or flows to the Pacific Ocean and salt sinks like saline groundwater aquifers. The remaining portion is distributed among urban and agricultural uses and for diversions to managed wetlands (DWR, 2010).

Residential Water Use

While single-family homes are estimated to account for about 60 percent of the total occupied housing stock in 2020, they are responsible for about 75 percent of total residential water demands. This is consistent with the fact that single-family households are known to use more water than multifamily households (e.g., those residing in duplexes, triplexes, apartment buildings and condo developments) on a per housing-unit basis. This is because single-family households tend to have more persons living in the household; they are likely to have more water-using appliances and fixtures; and they tend to have more landscaping (MWD, 2021).

Non-residential Water Use

Nonresidential water use represents an approximately 18 percent of the total municipal and industrial demands in MWD's service area in 2020. This includes water that is used by businesses, services, government, institutions (such as hospitals and schools), and industrial (or manufacturing) establishments. Within the commercial/institutional category, the top water users include schools, hospitals, hotels, amusement parks, colleges, laundries, and restaurants. In Southern California, major industrial users include electronics, aircraft, petroleum refining, beverages, food processing, and other industries that use water as a major component of the manufacturing process (MWD, 2020).

[82] The California Water Plan, DWR, 1998.

3.4.4 Water Supply

To meet current and growing demands for water, the South Coast region is leveraging all available water resources: imported water, water transfers, conservation, captured surface water, groundwater, recycled water, and desalination. Given the level of uncertainty about water supply from the Delta and Colorado River, local agencies have emphasized diversification. Local water agencies now utilize a diverse mixture of local and imported sources and water management strategies to adequately meet urban and agricultural demands each year (DWR, 2015).

Water used in MWD's service area comes from both local and imported sources. Local sources include groundwater, surface water, and recycled water. Sources of imported water include the Colorado River, the SWP, and the Owens Valley/Mono Basin. Local sources meet about 45 percent of the water needs in MWD's service area, while imported sources supply the remaining 55 percent (MWD, 2015).

The City of Los Angeles imports water from the eastern Owens Valley/Mono Basin in the Sierra Nevada through the LAA. This water currently meets about seven percent of the region's water needs based on a five-year average from 2005-2009, but is dedicated for use by the city of Los Angeles. Contractually and for planning purposes, MWD treats the LAA as a local supply, although physically its water is imported from outside the region. Other supplies come from local sources, and MWD provides imported water supplies to meet the remaining 47 percent of the region's water needs based on the same five-year period. These imported supplies are received from MWD's CRA and the SWP's California Aqueduct (MWD, 2020).

3.4.4.1 Imported Water Supplies

Water is brought into the South Coast region from three major sources: the Delta, Colorado River, and Owens Valley/Mono Basin. All three are facing water supply cutbacks due to climate change and environmental issues. Although historically imported water served to help the South Coast region grow, it is today relied upon to sustain the existing population and economy. As such, parties in the South Coast region are working closely with other regions, the State, and federal agencies to address the challenges facing these imported supplies. Meanwhile, the South Coast region is working to develop new local supplies to meet the needs of future population and economic growth (DWR, 2011).

Most MWD member agencies and retail water suppliers depend on imported water for a portion of their water supply. For example, Los Angeles and San Diego (the largest and second largest cities in the state) have historically (1995-2004) obtained about 85 percent of their water from imported sources. These imported water requirements are similar to those of other metropolitan areas within the state, such as San Francisco and other cities around the San Francisco Bay (MWD, 2015). A list of major water suppliers operating within the district region is given in Table 3.4-3.

Table 3.4-3
Major Water Suppliers in the South Coast AQMD Region

Water Agency	Land Area (square miles)	Sources of Water Supply
Antelope Valley and East Kern District	2,300	SWP, groundwater, reclaimed water
Bard Irrigation District (and Yuma Project Reservation Division)	23	Colorado River
Castaic Lake Water Agency	125	SWP and groundwater
Coachella Valley Water District	974	SWP, Colorado River, and local
Crestline Lake Arrowhead	78	SWP
Desert Water Agency	324	SWP, Colorado River, and groundwater
Imperial Irrigation District	1,658	Colorado River
Littlerock Creek Irrigation District	16	SWP, groundwater, and surface water
Metropolitan Water District of Southern California	5,200	SWP, Colorado River
Mojave Water Agency	4,900	SWP and groundwater
Palmdale Water Agency	187	SWP and groundwater
Palo Verde Irrigation District	189	Colorado River
San Bernardino Municipal Water	328	SWP and groundwater
San Gorgonio Pass Water Agency	225	Groundwater

Source: Draft Program EIR for the 2012-2035 RTP/SCS; SCAG; December 2011, p. 3.13-20.

State Water Project

The SWP is an important source of water for the South Coast region wholesale and retail suppliers. SWP contractors in the region take delivery of and convey the supplies to regional wholesalers and retailers. Contractors in the region are MWD, Castaic Lake Water Agency, San Bernardino Valley Municipal Water District, Littlerock Creek Irrigation District, Palmdale Water District, Crestline – Lake Arrowhead Water Agency, San Gorgonio Pass Water Agency, Desert Water Agency, Coachella Valley Water District, and San Gabriel Valley Municipal Water District (DWR, 2011).

The SWP provides imported water to the MWD service area. Since 2002, SWP deliveries have accounted for as much as 70 percent of its water. In accordance with its contract with the DWR, MWD has a "Table A" allocation of about 1.91 million acre-feet per year under contract from the SWP. Actual deliveries have never reached this amount because they depend on the availability of supplies as determined by DWR. The availability of SWP supplies for delivery through the California Aqueduct over the next 18 years is estimated according to the historical record of hydrologic conditions, existing system capabilities as may be influenced by environmental permits, requests from state water contractors and SWP contract provisions for allocating Table A, Article 21 and other SWP deliveries. The estimates of SWP deliveries to MWD are based on DWR's most recent SWP reliability estimates contained in its SWP

Delivery Reliability Report 200716 and the December 2009 draft of the biannual update (MWD, 2015). The amount of precipitation and runoff in the Sacramento and San Joaquin watersheds, system reservoir storage, regulatory requirements, and contractor demands for SWP supplies impact the quantity of water available to MWD (MWD, 2015).

MWD and 28 other public entities have contracts with the State of California for SWP water. These contracts require the state, through its DWR, to use reasonable efforts to develop and maintain the SWP supply. The state has constructed 28 dams and reservoirs, 26 pumping and generation plants, and about 660 miles of aqueducts. More than 25 million California residents benefit from water from the SWP. DWR estimates that with current facilities and regulatory requirements, the project will deliver approximately 2.3 million acre-feet under average hydrology considering impacts attributable to the combined Delta smelt and salmonid species biological opinions (MWD, 2015). Under the water supply contract, DWR is required to use reasonable efforts to maintain and increase the reliability of service to its users.

Colorado River System

Another key imported water supply source for the South Coast region is the Colorado River. California water agencies are entitled to 4.4 million acre-feet annually of Colorado River water. Of this amount, 3.85 million acre-feet are assigned in aggregate to agricultural users; 550,000 acre-feet is MWD’s annual entitlement. Until a few years ago, MWD routinely had access to 1.2 million acre-feet annually because Arizona and Nevada had not been using their full entitlement and the Colorado River flow was often adequate enough to yield surplus water (DWR, 2012).

A number of water agencies within California have rights to divert water from the Colorado River. Through the Seven Party Agreement (1931), seven agencies recommended apportionments of California’s share of Colorado River water within the state. Table 3.4-4 shows the historic apportionment of each agency, and the priority accorded that apportionment.

The water is delivered to MWD’s service area by way of the CRA, which has a capacity of nearly 1,800 cubic feet per second or 1.3 million acre-feet per year. The CRA conveys water 242 miles from its Lake Havasu intake to its terminal reservoir, Lake Mathews, near the city of Riverside. Conveyance losses along the Colorado River Aqueduct of 10 thousand acre-feet per year reduce the amount of Colorado River water received in the coastal plain (MWD, 2015).

Table 3.4-4
Priorities of the Seven Party Agreement

Priority	Description	TAF[(a)] Annually
1	Palo Verde Irrigation District – gross area of 104,500 acres of land in the Palo Verde Valley	3,850
2	Yuma Project (Reservation Division) – not exceeding a gross area of 25,000 acres in California	
3(a)	Imperial Irrigation District and land in Imperial and Coachella Valleys[b] to be served by All American Canal	
3(b)	Palo Verde Irrigation District—16,000 acres of land on the Lower Palo Verde Mesa	
4	Metropolitan Water District of Southern California for use on the coastal plain of Southern California[c]	550
Subtotal		**4,400**
5(a)	Metropolitan Water District of Southern California for use on the coastal plain of Southern California	550
5(b)	Metropolitan Water District of Southern California for use on the coastal plain of Southern California[c]	112
6(a)	Imperial Irrigation District and land in Imperial and Coachella Valleys to be served by the All American Canal	300
6(b)	Palo Verde Irrigation District—16,000 acres of land on the Lower Palo Verde Mesa	
7	Agricultural Use in the Colorado River Basin in California	
	Total Prioritized Apportionment	**5,362**

Source: MWD, 2015

(a) TAF = thousand acre-feet.
(b) The Coachella Valley Water District now serves Coachella Valley
(c) In 1946, the City of San Diego, the San Diego County Water Authority, Metropolitan, and the Secretary of the Interior entered into a contract that merged and added the City of San Diego's rights to store and deliver Colorado River water to the rights of MWD. The conditions of that agreement have long since been satisfied.

Since the date of the original contract, several events have occurred that changed the dependable supply that MWD expects from the CRA. The most significant event was the 1964 U.S. Supreme Court decree in Arizona v. California that reduced MWD's dependable supply of Colorado River water to 550 thousand acre-feet per year. The reduction in dependable supply occurred with the commencement of Colorado River water deliveries to the Central Arizona Project (MWD, 2015). The court decision lead to a number of other contracts and agreements on how Colorado River water is divided among various users, the key ones of which are summarized below (MWD, 2015).

- In 1987, MWD entered into a contract with the United States Bureau of Reclamation (USBR) for an additional 180 thousand acre-feet per year of surplus water, and 85 thousand acre-feet per year through a conservation program with the Imperial Irrigation District.
- In 1979, the Present Perfected Rights of certain Indian reservations, cities, and individuals along the Colorado River were quantified.

- In 1999, California's Colorado River Water Use Plan was developed to provide a framework for how California would make the transition from relying on surplus water supplies from the Colorado to living within its normal water supply apportionment. To implement these plans, the Quantification Settlement Agreement (QSA) and several other related agreements were executed. The QSA quantifies the use of water under the third priority of the Seven Party Agreement and allows for implementation of agricultural conservation, land management, and other programs identified in MWD's 1996 Integrated Water Resources Plan (IRP). The QSA has helped California reduce its reliance on Colorado River water above its normal apportionment.
- In October 2004, the Southern Nevada Water Authority and MWD entered into a storage and interstate release agreement. Under this program, Nevada can request that MWD to store unused Nevada apportionment in MWD's service area. The stored water provides flexibility to MWD for blending Colorado River water with SWP water and improves near-term water supply reliability.
- In December 2007, the Secretary of the Interior approved the adoption of specific interim guidelines for reductions in Colorado River water deliveries during declared shortages and coordinated operations of Lake Powell and Lake Mead.
- In May 2006, the MWD and the USBR executed an agreement for a demonstration program that allowed the MWD to leave conserved water in Lake Mead that MWD would otherwise have used in 2006 and 2007. As of January 1, 2010, MWD had nearly 80 thousand acre-feet of conservation water stored in Lake Mead (MWD, 2010).
- The December 2007 federal guidelines provided the Colorado River contractors with the ability to create system efficiency projects. By funding a portion of the reservoir projects at Imperial Dam, an additional 100 thousand acre-feet of water was allocated to MWD.

On August 16, 2021, the Bureau of Reclamation released its Colorado River Basin 24-Month Study. Because it is projected that the elevation in Lake Mead's water levels will decrease to 1,065 feet in January 1, 2022 (nine feet below the Lower Basin shortage determination trigger and 24 feet below the drought contingency plan trigger), Lake Mead will operate in a Level 1 Shortage Condition for 2022, the first time ever in its history. While there will be no effect on the water supply to MWD, water supply to Arizona will decrease by 512,000 acre-feet, Nevada: 21,000 acre-feet, and Mexico: 80,000 acre-feet.[83] California is not required to contribute supplies to Lake Mead under the Drought Contingency Plan, but a further lowering could trigger a required contribution in the future.[84]

<u>Owens Valley Mono Basin (Los Angeles Aqueduct)</u>

High-quality water from the Mono Basin and Owens Valley is delivered through the LAA to the City of Los Angeles. Construction of the original 233-mile aqueduct from the Owens Valley was completed in 1913, with a second aqueduct completed in 1970 to increase capacity. Approximately 480,000 acre-feet per year of water can be delivered to the City of

83 https://www.usbr.gov/newsroom/#/news-release/3950
84 https://www.mwdh2o.com/newsroom-press-releases/metropolitan-statement-on-colorado-river-shortage-declaration/

Los Angeles each year; however, the amount of water the aqueducts deliver varies from year to year due to fluctuating precipitation in the Sierra Nevada Mountains and mandatory instream flow requirements (DWR, 2012).

Diversion of water from Mono Lake has been reduced following State Water Board Decision 1631. Exportation of water from the Owens Valley is limited by the Inyo-Los Angeles Long Term Water Agreement (and related Memorandum of Understanding) and the Great Basin Air Pollution Control District/City of Los Angeles Memorandum of Understanding (to reduce particulate matter air pollution from the Owens Lake bed) (DWR, 2012).

Over time, environmental considerations have required that the City reallocate approximately one-half of the LAA water supply to environmental mitigation and enhancement projects. As a result, the City of Los Angeles has used approximately 205,800 acre-feet of water supplies for environmental mitigation and enhancement in the Owens Valley and Mono Basin regions in 2010, which is in addition to the almost 107,300 acre-feet per year supplied for agricultural, stockwater, and Native American Reservations. Limiting water deliveries to the City of Los Angeles from the LAA has directly led to increased dependence on imported water supply from MWD. LADWP's purchases of supplemental water from MWD in FY 2008/09 reached an all-time high (LADWP, 2010).

LAA deliveries comprise 39 percent of the total runoff in the eastern Sierra Nevada in an average year. The vast majority of water collected in the eastern Sierra Nevada stays in the Mono Basin, Owens River, and Owens Valley for ecosystem and other uses (LADWP, 2010).

Annual LAA deliveries are dependent on snowfall in the eastern Sierra Nevada. Years with abundant snowpack result in larger quantities of water deliveries from the LAA, and typically lower supplemental water purchases from MWD. Unfortunately, a given year's snowpack cannot be predicted with certainty, and thus, deliveries from the LAA system are subject to significant hydrologic variability (LADWP, 2010).

The impact to LAA water supplies due to varying hydrology in the Mono Basin and Owens Valley is amplified by the requirements to release water for environmental restoration efforts in the eastern Sierra Nevada. Since 1989, when City water exports were significantly reduced to restore the Mono Basin's ecosystem, LAA deliveries from the Mono Basin and Owens Valley have ranged from 108,503 acre-feet in 2008/09 to 466,584 acre-feet in 1995/96. Average LAA deliveries since 1989/90 have been approximately 264,799 acre-feet, about 42 percent of the City of Los Angeles' total water needs (LADWP, 2010).

3.4.4.2 Local Water Supplies

Approximately 50 percent of the region's water supplies come from resources controlled or operated by local water agencies. These resources include water extracted from local groundwater basins, catchment of local surface water, non-MWD imported water supplied through the Los Angeles Aqueduct, and Colorado River water exchanged for MWD supplies (MWD, 2015).

Local sources of water available to the region include surface water, groundwater, and recycled water. Some of the major river systems in southern California have been developed into systems of dams, flood control channels, and percolation ponds for supplying local water and recharging groundwater basins. For example, the San Gabriel and Santa Ana rivers capture over 80 percent of the runoff in their watersheds. The Los Angeles River system, however, is not as efficient in capturing runoff. In its upper reaches, which make up 25 percent of the watershed, most runoff is captured with recharge facilities. In its lower reaches, which comprise the remaining 75 percent of the watershed, the river and its tributaries are lined with concrete, so there are no recharge facilities. The Santa Clara River in Ventura County is outside of MWD's service area, but it replenishes groundwater basins used by water agencies within MWD's service area. Other rivers in MWD's service area, such as the Santa Margarita and San Luis Rey, are essentially natural replenishment systems (MWD, 2015).

3.4.4.3 Surface Water

Local surface capture plays an important water resource role in the South Coast region. More than 75 impound structures are used to capture local runoff for direct use or groundwater recharge, operational or emergency storage for imported supplies, or flood protection. While precipitation contributes most of the annual volume of streamflow to the region's waterways, urban runoff, wastewater discharges, agricultural tailwater, and surfacing groundwater are the prime sources of surface flow during non-storm periods. The South Coast has experienced a trend of increasing dry weather flows during the past 30 years as the region has developed, due to increased imported water use and associated urban runoff (DWR, 2011).

Surface water runoff augments groundwater and surface water supplies. However, the regional demand far surpasses the potential natural recharge capacity. The arid climate, summer drought, and increased urbanization contribute to the inadequate natural recharge. Urban and agricultural runoff can contain pollutants, which decrease the quality of local water supplies. Local agencies maintain surface reservoir capacity to capture local runoff. The average yield captured from local watersheds is estimated at approximately 90 thousand acre-feet per year. The majority of this supply comes from reservoirs within the service area of the San Diego County Water Authority (MWD, 2015).

3.4.4.4 Groundwater

During the first half of the 20th century, groundwater was an important factor in the expansion of the urban and agricultural sectors in the South Coast region. Today, it remains important for the Santa Clara, MWD Los Angeles and Santa Ana planning areas, but only a small source for San Diego. Court adjudications recharge operations, and other management programs are helping to maintain the supplies available from many of the region's groundwater basins. Since the 1950s, conjunctive management and groundwater storage has been utilized to increase the reliability of supplies, particularly during droughts. Using the region's other water resources, groundwater basins are being recharged through spreading basins and injection wells. During water shortages of the imported supplies, more groundwater would be extracted to make up the difference. Water quality issues have impacted the reliability of supplies from some basins. However, major efforts are underway to address the problems and increase supplies for these basins (DWR, 2010).

The groundwater basins that underlie the region provide approximately 86 percent of the local water supply in southern California. The major groundwater basins in the region provide an annual average supply of approximately 1.35 million acre-feet. Most of this water recharges naturally, but approximately 200 thousand acre-feet has historically been replenished each year through MWD imported supplies. By 2025, estimates show that groundwater production will increase to 1.65 million acre-feet (MWD, 2015).

Because the groundwater basins contain a large volume of stored water, it is possible to produce more than the natural recharge of 1.16 million acre-feet and the imported replenishment amount for short periods of time. During a dry year, imported replenishment deliveries can be postponed, but doing so requires that the shortfall be restored in wet years. Similarly, in dry years the level of the groundwater basins can be drawn down, as long as the balance is restored to the natural recharge level by increasing replenishment in wet years. Thus, the groundwater basins can act as a water bank, allowing deposits in wet years and withdrawals in dry years (MWD, 2015).

3.4.4.5 Recycled Water

Local water recycling projects involve further treatment of secondary treated wastewater that would be discharged to the ocean or streams and use it for direct non-potable uses such as landscape and agricultural irrigation, commercial and industrial purpose and for indirect potable uses such as groundwater recharge, seawater intrusion barriers, and surface water augmentation (MWD, 2015).

Within MWD's service area, there are approximately 355,000 acre-feet of planned and permitted uses of recycled water supplies. Actual use is approximately 209,000 acre-feet, which includes golf course, landscape, and cropland irrigation; industrial uses; construction applications; and groundwater recharge, including maintenance of seawater barriers in coastal aquifers. MWD projects the development of 500,000 acre-feet of recycled water supplies (including groundwater recovery) by 2025 (DWR, 2010).

Current average annual recycled water production in the MWD Los Angeles Planning Area is approximately 225 million gallons per day (mgd), which represents approximately 25 percent of the current average annual effluent flows. The Water Replenishment District (WRD) is permitted to recharge up to 50,000 acre-feet per year (45 mgd) of Title 22 recycled water for ground water replenishment of the Montebello Forebay. West Basin Municipal Water District's (WBMWD) Edward C. Little Water Recycling Facility in El Segundo, produces recycled water that is distributed either directly to their customers or transferred to one of three satellite facilities where the recycled water can be treated to meet customer specifications. The satellite facilities are the Torrance Refinery Water Recycling Plant in Torrance, CA, the Chevron Nitrification Treatment Plant in El Segundo, CA, and the Juanita Millender-McDonald Carson Regional Water Recycling Plant in Carson, CA. WBMWD provides recycled water to several locations including but not limited to the cities of Carson, El Segundo, and unincorporated areas of Los Angeles County within its service area. WBMWD's recycled water distribution infrastructure includes over 100 miles of pipelines and is separate from the potable water distribution system.

In 2020, WBMWD produced approximately 28,046 acre-feet, and completed its Phase V Expansion Project in 2014. Recycled water use within WBMWD's service area is projected to increase to 76,300 acre-feet per year by 2045, representing 39 percent of total supplies. Approximately 15,000 acre-feet per year of the recycled water produced at this facility is purchased by WRD and injected into the West Coast Barrier. The use of recycled water by LADWP is projected to be approximately 60,700 acre-feet per year by 2030 (WBMWD, 2020), 2010).

Within Los Angeles County, recycled water is also distributed to industrial customers from the Harbor Refineries Recycled Water Pipeline (HRRWP) which is maintained by the Los Angeles Department of Water and Power (LADWP), in conjunction with the West Basin Municipal Water District (WBMWD). The LADWP/WBMWD provide approximately 35 mgd of recycled water to its industrial customers. The WBMWD has also expanded its Hyperion Pump Station to accommodate a throughput of 70 mgd of source water which would result in about 55 to 60 mgd of saleable recycled water if, and when needed to accommodate any increased need by their customers.

3.4.4.6 Desalination Plants

In the MWD Los Angeles Planning Area, the Robert W. Goldsworthy Desalter, owned and operated by the WRD, processes approximately 2.75 mgd of brackish groundwater desalination for the purpose of remediating a saline plume located within the West Coast sub-basin and providing a reliable local water source to Torrance (DWR, 2010).

Also, WBMWD is proposing a new Ocean Water Desalination Project, to be located in an industrially-zoned location within the El Segundo Generating Station (ESGS) at 301 Vista del Mar in the City of El Segundo, California that would produce between 20 to 60 mgd of drinking water from the ocean. The 20 mgd capacity facility would generate approximately 21,500 acre-feet per year of high-quality, drinking water to meet local demand and would add approximately 20 percent of reliable water to the service area. Potential expansion of this facility to produce up to 60 MGD of drinking water to account for future needs in the region is also under consideration.[85]

3.4.5 Water Conservation

In the MWD Los Angeles Planning Area, MWD assists member agencies with implementation of water conservation programs. MWD's conservation programs focus on two main areas: residential programs, and commercial, industrial and institutional programs.

Water conservation continues to be a key factor in water resource management in southern California. For MWD, water-use efficiency is anchored by the adopted Long-Term Conservation Plan (LTCP) (August 2011) and the Local Resources Program (LRP). The LTCP sets goals to help retailers achieve water conservation savings, and at the same time, support technology innovation and transform public perception about the value of water. This plan is market oriented and has both incentive and non-incentive drivers to ultimately change how water is used by southern

[85] West Basin Municipal Water District, https://www.westbasin.org/desalination/project-overview/, accessed August 2021.

California consumers. Additionally, the LRP encourages the development and increased use of recycled water through incentives (MWD, 2012).[86]

Outdoor water use is a key focus as watering landscapes and gardens accounts for about half of household water use in MWD's service area. MWD will work with water agencies, landscape equipment manufacturers and other stakeholders to make proper irrigation control more effective and easier to understand. A similar effort will be made to reach out to the region's businesses, industries and agriculture to focus on process improvements that can save both money and water. The final focus will be on residential water use, where MWD will work with water agencies and energy utilities to better promote the choices that consumers have for water-efficient products like faucets, shower heads and high-efficiency clothes washers (MWD, 2012).

MWD's incentive programs aimed at residential, commercial and industrial water users make a key contribution to the region's conservation achievements. The rebate program is credited with water savings of 156,000 acre-feet annually. Funding provided by MWD to member agencies and retail water agencies for locally-administered conservation programs included rebates for turf removal projects, toilet distribution and replacement programs, high-efficiency clothes washer rebate programs and residential water audits (MWD, 2012).

3.4.5.1 Residential Programs

MWD's residential conservation consists of the following programs:

- SoCal Water$mart: A region-wide program to help offset the purchase of water-efficient devices. MWD issued 54,000 rebates for residential fixtures in fiscal year 2008/09, resulting in approximately 2.3 thousand acre-feet of water to be saved annually.
- Save Water, Save A Buck: This program extends rebates to multi-family dwellings. More than 40,000 rebates were issued fiscal year 2008/09 for high-efficiency toilets and washers for multi-family units.
- Member Agency Residential Programs: member and retail agencies also implement local water conservation programs within their respective service areas and receive MWD incentives for qualified retrofits and other water-saving actions. Typical projects include toilet replacements, locally administered clothes washer rebate programs, and residential water audits.

MWD has provided incentives on a variety of water efficient devices for the residential sector, including: 1) high-efficiency clothes washers; 2) high-efficiency toilets and ultra-low toilets; 3) irrigation evaluations and residential surveys; 4) rotating nozzles for sprinklers; 5) weather-based irrigation controllers; and, 6) synthetic turf.

[86] Annual Progress Report to the California State Legislature, Metropolitan Water District; February, 2012.

3.4.5.2 Commercial, Industrial and Institutional Programs

MWD's commercial industrial and institutional conservation consists of three major programs:

- Save Water, Save-A-Buck Program: The Save-A-Buck program had its largest year in fiscal year 2008/09, providing rebates for approximately 145,000 device retrofits.
- Water Savings Performance Program: This program allows large-scale water users to customize conservation projects and receive incentives for five years of water savings for capital water-use efficiency improvements.
- Member Agency Commercial Programs: Member and retail agencies also implement local commercial water conservation programs using MWD incentives.

A fourth program, the Public Sector Demonstration Program also resulted in water savings. From August 2007 through 2008, MWD offered a one-time program to provide up-front funding to increase water use efficiency in public buildings and landscapes within its service area. Participants included various special districts, school districts, state colleges and universities, municipalities, counties, and other government agencies.

- Enhanced incentives were provided to replace high water-use equipment including toilets, urinals, and irrigation controllers. Program incentives were often sufficient to cover the total cost of the equipment.
- Pay-for-performance incentives were also offered to reduce landscape irrigation water use by at least 10 percent through behavioral modifications.
- MWD' s programs provide rebates for water-saving plumbing fixtures, landscaping equipment, food-service equipment, cleaning equipment, HVAC (heating, ventilating, air conditioning) and medical equipment.

LADWP implements public outreach and school education programs to encourage conservation ethics; seasonal water rates that are approximately 20 percent greater during the summer high use period; and free water conservation kits. In addition, LADWP implemented Mandatory Water Conservation measures in 2009, which are still in effect today. Mandatory Water Conservation restricts outdoor watering and prohibits certain uses of water such as prohibiting customers from hosing down driveways and sidewalks, requiring all leaks to be fixed, and requiring customers to use hoses fitted with shut-off nozzles. As a result of these conservation efforts by LADWP, the water demand for Los Angeles is about the same as it was 25 years ago, despite a population increase of more than one million people. LADWP projects an additional savings of at least 50,000 acre-feet per year by 2030 through additional water conservation programs. The Central Basin Municipal Water District and the WBMWD also have water conservation master plans to coordinate and prioritize conservation efforts and identify enforcement protocols.

CHAPTER 4

ENVIRONMENTAL IMPACTS

4.0 INTRODUCTION

The CEQA Guidelines require environmental documents to identify significant environmental effects that may result from a proposed project. [CEQA Guidelines Section 15126.2(a)]. Direct and indirect significant effects of a project on the environment should be identified and described, with consideration given to both short- and long-term impacts. The discussion of environmental impacts may include, but is not limited to: the resources involved; physical changes; alterations of ecological systems; health and safety problems caused by physical changes; and other aspects of the resource base, including water, scenic quality, and public services. If significant adverse environmental impacts are identified, the CEQA Guidelines require a discussion of measures that could either avoid or substantially reduce any adverse environmental impacts to the greatest extent feasible [CEQA Guidelines Section 15126.4].

The categories of environmental impacts to be studied in a CEQA document are established by CEQA (Public Resources Code Section 21000 et seq.), and the CEQA Guidelines, as codified in Title 14 California Code of Regulations Section 15000 et seq. Under the CEQA Guidelines, there are approximately 18 environmental categories in which potential adverse impacts from a project are evaluated. The South Coast AQMD, as lead agency, has taken into consideration the Appendix G environmental checklist form, but has tailored the 21 environmental topic areas to emphasize air quality assessment primarily by combining the "air quality" and "greenhouse gas emissions" areas into one section, combining the "cultural resources" and "tribal cultural resources" areas into one section, separating the "hazards and hazardous materials" factor into two sections: "hazards and hazardous materials" and "solid and hazardous waste," and folding the "utilities/service systems" area into other environmental areas such as "energy," "hydrology and water quality" and "solid and hazardous waste." For each environmental topic area, per CEQA Guidelines Section 15064.7(a), "a threshold of significance is an identifiable quantitative, qualitative or performance level of a particular environmental effect, non-compliance with which means the effect will normally be determined to be significant by the agency and compliance with which means the effect normally will be determined to be less than significant." The South Coast AQMD has developed unique thresholds of significance for the determination of significance in accordance with CEQA Guidelines Section 15064.7(b), and they are located in the significance criteria section of the air quality and greenhouse gas emissions, hazards and hazardous materials, and hydrology sub-chapters.

The CEQA Guidelines also indicate that the degree of specificity required in a CEQA document depends on the type of project being proposed. [CEQA Guidelines Section 15146]. The detail of the environmental analysis for certain types of projects cannot be as great as for others. As explained in Chapter 1, the analysis of the proposed project indicated that a SEA is the appropriate type of CEQA document to be prepared.

4.1 POTENTIAL SIGNIFICANT ENVIRONMENTAL IMPACTS AND MITIGATION MEASURES

PRs 1109.1 and 429.1, PARs 1304 and 2005, and the proposed rescission of Rule 1109 comprise the proposed project which is being evaluated in this SEA. As allowed by CEQA Guidelines Section 15152, this SEA is tiering off of the December 2015 Final PEA for NOx RECLAIM and the March 2017 Final Program EIR for the 2016 AQMP for the following reasons:

1) The proposed project applies to 16 refinery-sector facilities and their specified combustion equipment, which are all participants of the NOx RECLAIM program that was the subject the NOx emission reduction commitment in Control Measure CMB-05 in the 2016 AQMP and the environmental impacts associated with implementing Control Measure CMB-05 were previously analyzed in March 2017 Final Program EIR.

2) The 16 refinery sector facilities that are subject to the proposed project were also subject to the December 2015 amendments to the NOx RECLAIM program and the environmental impacts associated with these amendments were previously analyzed December 2015 Final PEA for NOx RECLAIM. Moreover, nine of the 16 refinery-sector facilities that are subject to the proposed project were specifically identified and the environmental impacts associated with undergoing physical modifications to install new or modify existing air pollution control equipment were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. However, the previous analyses for some of these nine facilities may have been based on employing greater numbers of air pollution control equipment with more overall environmental impacts (e.g., more scrubbers and new SCRs) than what would be expected to be installed under the current BARCT proposal (e.g., fewer scrubbers, fewer new SCRs but more upgraded SCRs, and burner replacements with ULNBs). Since the previous analysis may have overestimated potential impacts for some combustion equipment categories, some updates to the previous environmental analysis for these nine facilities are needed.

3) While seven refinery-sector facilities did not have detailed environmental impacts analyzed in the December 2015 Final PEA for NOx RECLAIM, the currently proposed BARCT NOx emissions levels for these facilities' combustion equipment can be achieved by the same types of air pollution control equipment that were analyzed in the December 2015 Final PEA for NOx RECLAIM. Some updates to the previous environmental analysis are needed to incorporate analyses for these seven additional facilities.

Background on December 2015 Amendments to the NOx RECLAIM Program and the December 2015 Final PEA

Amendments to the NOx RECLAIM program were adopted in December 2015 to comply with the requirements in Health and Safety Code Sections 40440 and 39616 by conducting a BARCT assessment. The December 2015 amendments to the NOx RECLAIM program were designed to reduce NOx emissions from equipment and processes operated at NOx RECLAIM facilities located within South Coast AQMD's jurisdiction. The December 2015 Final PEA for NOx RECLAIM programmatically analyzed the potential environmental impacts that could potentially occur as a result of 20 facilities from both the refinery and non-refinery sectors, nine and 11 respectively, installing new, or modifying existing, control equipment for the following types of equipment/source categories in the NOx RECLAIM program: 1) FCCUs; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) SRU/TGs; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant internal combustion engines; 8) container glass melting furnaces; 9) coke calcining; and, 10) metal heat treating furnaces. The analysis in the December 2015 Final PEA for NOx RECLAIM concluded 14 tons per day of NOx emission reductions would be achieved but that significant adverse environmental impacts to the topics of air quality and GHGs, hydrology (water demand), and, hazards and hazardous materials (due to ammonia transportation) would also occur as a result of amending the NOx RECLAIM program if NOx reduction projects were implemented in lieu of or in addition to facilities surrendering NOx RTCs. The analysis also indicated that an overall regional reduction of 0.1 $\mu g/m^3$ PM2.5 emissions would occur. The following air pollution control technologies were identified as being expected to achieve the projected NOx emission reductions at the affected facilities and the environmental impacts from employing these technologies were analyzed in the December 2015 Final PEA for NOx RECLAIM: SCRs, LoTOx™ with and without a WGS, and UltraCat™ with DGS that were analyzed.

Since significant adverse environmental impacts were identified in the December 2015 Final PEA for NOx RECLAIM, mitigation measures were identified and applied. However, the December 2015 Final PEA concluded that the project would have significant and unavoidable adverse environmental impacts even after mitigation measures were identified and applied. As such, mitigation measures were made a condition of project approval and a Mitigation Monitoring Plan was adopted. Findings were made and a Statement of Overriding Considerations was adopted.[1]

Background on March 2017 Adoption of the 2016 AQMD and the March 2017 Final Program EIR

The 2016 AQMP was adopted in March 2017 and identified control measures and strategies to bring the region into attainment with the revoked 1997 8-hour NAAQS (80 ppb) for ozone by 2024; the 2008 8-hour ozone standard (75 ppb) by 2032; the 2012 annual PM2.5 standard (12 $\mu g/m^3$) by 2025; the 2006 24-hour PM2.5 standard (35 $\mu g/m^3$) by 2019; and the revoked 1979 1-hour ozone standard (120 ppb) by 2023. The 2016 AQMP consists of three components: 1) the South Coast AQMD's Stationary, Area, and Mobile Source Control Measures; 2) State and Federal Control Measures provided by the California Air Resources Board; and 3) Regional Transportation Strategy and Control Measures provided by the Southern California Association of Governments. The 2016 AQMP includes emission inventories and control measures for stationary, area and mobile sources, the most current air quality setting, updated growth projections, new modeling techniques, demonstrations of compliance with state and federal Clean Air Act requirements, and an implementation schedule for adoption of the proposed control strategy. Of the control measures in the 2016 AQMP, Control Measure CMB-05 – Further NOx Reductions from RECLAIM Assessment, committed to achieving NOx emission reductions of five tons per day by 2025 as an acknowledgement that many of the RECLAIM program's original advantages were diminishing. For this reason, the South Coast AQMD Governing Board directed staff to implement an orderly sunset of the RECLAIM program to achieve the additional five tons per day. Thus, CMB-05 committed to a process of transitioning NOx RECLAIM facilities to a command-and-control

[1] South Coast AQMD, Attachment 1 to the Governing Board Resolution for the Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), Findings, Statement of Overriding Considerations and Mitigation Monitoring Plan. December 2015. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2015/regxxfindings.pdf

regulatory structure and to ensure that the applicable equipment will meet BARCT level equivalency as soon as practicable.

For the entire 2016 AQMP, the analysis in the March 2017 Final Program EIR concluded significant and unavoidable adverse environmental impacts from the project are expected to occur after implementing mitigation measures for the following environmental topic areas: 1) aesthetics from increased glare and from the construction and operation of catenary lines and use of bonnet technology for ships; 2) construction air quality and GHGs; 3) energy (due to increased electricity demand); 4) hazards and hazardous materials due to: (a) increased flammability of solvents; (b) storage, accidental release and transportation of ammonia; (c) storage and transportation of liquefied natural gas (LNG); and (d) proximity to schools; 5) hydrology (water demand); 6) construction noise and vibration; 7) solid construction waste and operational waste from vehicle and equipment scrapping; and, 8) transportation and traffic during construction and during operation on roadways with catenary lines and at the harbors.

However, specific to the implementation of Control Measure CMB-0 5, the analysis in the March 2017 Final Program EIR for the 2016 AQMP concluded significant and unavoidable adverse environmental impacts would be expected to occur after implementing mitigation measures for the following topic areas: 1) air quality and GHGs during construction due to multiple facilities =undergoing simultaneous or overlapping construction; 2) hazards and hazardous materials due to the storage and accidental release of ammonia; 3) hazards and hazardous Materials due to the use of ammonia at facilities located near schools; and 4) hydrology (water demand). The following air pollution control technologies were identified in the March 2017 Final Program EIR as being expected to achieve the projected NOx emission reductions associated with implementing Control Measure CMB-05: SCR and selective non-catalytic reduction (SNCR) technologies.

Since significant adverse environmental impacts were identified in the March 2017 Final Program EIR, mitigation measures were identified and applied. However, the March 2017 Final Program EIR concluded that the 2016 AQMP would have significant and unavoidable adverse environmental impacts even after mitigation measures were identified and applied. As such, mitigation measures were made a condition of project approval and a Mitigation, Monitoring, and Reporting Plan was adopted. Findings were made and a Statement of Overriding Considerations was adopted for the 2016 AQMP.[2]

Proposed Project and Focus of Environmental Effects and Analysis

PR 1109.1 has been developed to replace outdated Rule 1109 and to implement BARCT for refinery-related sources. PR 1109.1 is expected to require physical modifications of existing equipment or processes that may result in secondary adverse environmental impacts. However, PR 429.1 and PARs 1304 and 2005 are companion rules to address challenges in implementing the requirements of PR 1109.1, and do not themselves impose any emission reduction requirements ; no physical modifications that would create any secondary adverse environmental impacts are expected to occur for this portion of the proposed project. See Chapter 2 of this SEA for a description of PR 429.1 and PARs 1304 and 2005. Thus, the analysis in this SEA focuses on physical modifications expected to occur as a result of PR 1109.1 and the corresponding environmental effects. This chapter also contains a review of the requirements in PR 429.1 and

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[2] South Coast AQMD, Attachment 2 to the Governing Board Resolution for the Final Program Environmental Impact Report for the 2016 Air Quality Management Plan, A, Findings, Statement of Overriding Considerations and Mitigation, Monitoring and Reporting Plan. March 2017, http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2017/att2toresolutionfor-2016aqmp.pdf.

PARs 1304 and 2005 as well as the requirements that will be replaced by PR 1109.1 after Rule 1109 is rescinded.

When considering December 2015 Final PEA for NOx RECLAIM and March 2017 Final Program EIR to determine the existing environmental setting for the proposed project, the baseline that was established at the time the NOP was published for Draft PEA for NOx RECLAIM (e.g., December 5, 2014) more directly corresponds to the currently proposed project since the affected facilities, the type of combustion equipment involved, and the physical impacts that may occur as a result of implementing the BARCT requirements in PR 1109.1 are expected to be the same or similar as the previous analysis. For this reason, the baseline selected for the analysis of the proposed project in this SEA is the project analyzed in the December 2015 Final PEA for NOx RECLAIM. Specifically, the proposed project is expected to substantially increase the severity of the significant effects that were previously examined in the December 2015 Final PEA for NOx RECLAIM. [CEQA Guidelines Section 15162(a)(3)(B)]. For this reason, this SEA analyzes the incremental changes that may occur subsequent to the project that was analyzed in the December 2015 Final PEA for NOx RECLAIM if proposed project is implemented.

To assess the physical changes that may occur if PR 1109.1 is implemented, this SEA examines the types of activities and associated environmental impacts with implementing the BARCT standards for the equipment and facilities subject to the December 2015 NOx RECLAIM amendments that were previously analyzed in the December 2015 Final PEA for NOx RECLAIM, refines and updates the previous calculation method with new emission factors and PR 1109.1 data, and estimates associated environmental impacts to the additional equipment and sources that will need to comply with the BARCT requirements in PR 1109.1. The baseline for the SEA analysis is the project analyzed in the 2015 NOx RECLAIM PEA. However, this SEA takes a conservative approach to evaluating significance. The impacts estimated for implementation of PR 1109.1 added with the impacts calculated in the December 2015 Final PEA for NOx RECLAIM are together evaluated for whether the proposed project will create significant adverse impacts.

The analysis in this SEA indicates that the physical activities that facility operators may undertake to comply with the BARCT requirements in PR 1109.1 are expected to require mostly the same air pollution control equipment technologies as analyzed in December 2015 Final PEA for NOx RECLAIM. For example, implementation of PR 1109.1 is expected to utilize SCRs, ULNBs, LoTOx™ with a WGS, and UltraCat™ with DGS while the analysis in the December 2015 Final PEA for NOx RECLAIM assumed that SCRs, LoTOx™ with and without a WGS, and UltraCat™ with DGS would be employed. Even with these slight differences between the two projects, the same or similar secondary adverse environmental impacts affecting the same environmental topic areas that were identified and analyzed in the December 2015 Final PEA for NOx RECLAIM (e.g., air quality and GHGs during construction, hazards and hazardous materials (due to ammonia transportation), and hydrology (water demand) are also expected to occur if PR 1109.1 is implemented. Secondary adverse environmental impacts refer to unintended but necessary consequences from the implementation of a project. For example, while the purpose and use of LoTOx™ with WGS ultimately reduces NOx emissions, the equipment utilizes water resulting in secondary adverse hydrology impacts, must be constructed resulting in secondary adverse construction air quality impacts, and will utilize electricity resulting in secondary adverse GHG impacts.

PR 1109.1 proposes to reduce NOx emissions from refinery equipment and transition equipment that is currently permitted under the NOx RECLAIM program to a command-and-control regulatory structure by requiring affected equipment operating at RECLAIM or former RECLAIM facilities to comply with current BARCT. For some equipment categories, existing burners in combustion equipment will be replaced with ULNBs, while for other equipment categories, SCRs or scrubbers will need to be installed. The analysis also considers the possibility of facility operators upgrading their existing SCRs instead of replacement. Table 4.1-1 summarizes the various BARCT control technology options for each equipment category subject to PR 1109.1.

Table 4.1-1
BARCT Control Technology Options for NOx-Emitting Equipment Categories

Equipment Category	BARCT Control Technology for Equipment Subject to PR 1109.1
Refinery Process Heaters and Boilers	1. New SCRs 2. Upgrade existing SCRs 3. Replace burners with ULNBs
Sulfur Recovery Unit / Tail Gas Units (SRU/TGs)	1. Replace burners with ULNBs
Fluid Catalytic Cracking Units (FCCUs)	1. New SCRs 2. LoTOx^{TM} with WGS
Thermal Oxidizers	1. Replace burners with ULNBs
Refinery Gas Turbines	1. SCR Upgrade
Coke Calciner	1. New SCRs 2. LoTOx^{TM} with WGS 3. UltraCat^{TM} with DGS

Key: SCR = Selective Catalytic Reduction; WGS = Wet Gas Scrubber; DGS = Dry Gas Scrubber

Of the 16 facilities that would be subject to PR 1109.1, the BARCT analysis found that it would be both feasible and cost-effective for operators of 11 facilities to install new air pollution control equipment or modify existing air pollution control equipment. Air pollution control technology projects were previously analyzed for nine of the 11 facilities in the December 2015 Final PEA for NOx RECLAIM. Regarding the remaining five facilities, one facility has equipment which is exempt from the BARCT standards in PR 1109.1 due to their low-use, and other equipment that is currently able to meet BARCT. Three facilities have equipment which are already controlled by SCR technology and either meet BARCT limits or conditional NOx limits under PR 1109.1. Lastly, one facility has equipment which are approaching the end of their useful life and will likely be replaced by emerging technology. Emerging technology is technology that can achieve NOx emission reductions but is not widely available at the time the NOx limits were established in PR 1109.1. The NOx emission reduction abilities of emerging technology have not yet been demonstrated to be achieved in practice, and as such, is considered emerging because it is under development. For this reason, PR 1109.1 neither requires the use of emerging technology nor relies on the potential associated NOx emission reductions to achieve BARCT. While the next generation of emerging technology may involve similar or less environmental impacts than the analysis of the NOx control technologies analyzed in this SEA, due to uncertainty as to which emerging control technology or technologies will ultimately be available and used, further analysis of emerging technologies in this SEA would be speculative. Thus, this SEA does not contain an analysis of construction and operation impacts, or the potential NOx emission reduction benefits, that may be associated with the future use of emerging technologies.

Implementation of the proposed project is estimated to result in approximately seven to eight tons per day of NOx emission reductions which will help improve the overall air quality in the South Coast AQMD's jurisdiction and further the progress towards attaining and maintaining state and NAAQS for ozone, PM10, and PM2.5.

The air pollution control equipment that was analyzed and the conclusions reached in the December 2015 Final PEA for NOx RECLAIM are not substantially different from the air pollution control technologies, support equipment, and chemicals that may be employed by the proposed project. As such, this chapter compares the types of activities and associated environmental impacts with implementing the BARCT standards for the equipment and facilities previously analyzed in the December 2015 Final PEA for NOx RECLAIM, to the additional equipment and sources that will need to comply with the BARCT requirements in PR 1109.1.

Due to these similarities, the environmental topic areas that may be expected to have significant adverse impacts for the proposed project are expected to be the same as the environmental topic areas that were concluded to have significant adverse impacts in the December 2015 Final PEA for NOx RECLAIM (e.g., air quality during construction and GHG emissions, hazards and hazardous materials due to ammonia, and hydrology (water demand)). In addition, because the proposed project does not contemplate the use of air pollution control technologies with new or unknown impacts, no new adverse impacts to other environmental topic areas that were not previously analyzed in the December 2015 Final PEA for NOx RECLAIM are expected to occur (see Section 4.5 of this chapter for a description and the basis for this conclusion). Thus, only the environmental topic areas of air quality during construction and GHG emissions, hazards and hazardous materials due to ammonia, and hydrology (water demand) are expected to continue to have significant adverse impacts as a result of the proposed project.

The environmental impact analysis for these potentially significant environmental topic areas in Sections 4.2 through 4.4 incorporate a "worst-case" approach. This approach entails the premise that whenever the analysis requires that assumptions be made, those assumptions that result in the greatest adverse impacts are typically chosen. This method ensures that all potential effects of the proposed project are documented for the decision-makers and the public. Accordingly, the following analyses apply a conservative "worst-case" approach for analyzing the potentially significant adverse impacts for air quality during construction and GHG emissions, hazards and hazardous materials due to ammonia, and hydrology (water demand) impacts associated with the implementation of the proposed project.

In addition, this chapter independently considers whether the proposed project would result in new significant impacts for any of the other environmental topic areas previously concluded in the December 2015 Final PEA for NOx RECLAIM to have either no significant impacts or less than significant impacts; however, none were identified. See Section 4.5 of this chapter for a description and the basis for this conclusion.

SUBCHAPTER 4.2

AIR QUALITY AND GREENHOUSE GAS EMISSIONS

4.2 AIR QUALITY AND GREENHOUSE GAS EMISSIONS

PR 1109.1 proposes to reduce NOx emissions from refinery equipment and transition equipment that is currently permitted under the NOx RECLAIM program to a command-and-control regulatory structure by requiring affected equipment operating at RECLAIM or former RECLAIM facilities to comply with current BARCT.

This chapter independently considers the currently proposed project and analyzes the incremental changes, if any, relative to the baseline established in the December 2015 Final PEA for NOx RECLAIM. The December 2015 Final PEA for NOx RECLAIM previously analyzed environmental impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS at 20 facilities, with nine from the refinery sector and 11 from the non-refinery sector . The NOP/IS for the Draft PEA for NOx RECLAIM identified the environmental topic of air quality and GHGs as having potentially significant adverse impacts which was further analyzed in the December 2015 Final PEA for NOx RECLAIM and concluded that significant adverse impacts to air quality during construction and GHG emissions would occur.

Seven additional facilities and additional equipment categories will apply to the proposed project when compared to the project analyzed in December 2015 Final PEA for NOx RECLAIM for 20 facilities, with nine from the refinery-sector. However, the same types of air pollution control equipment with similar impacts to the same environmental topic areas that were previously analyzed are expected to occur with the proposed project except that the proposed project will have an incremental increase in the number of new SCRs installed with the associated ammonia storage tanks and the number of existing SCRs upgraded. The proposed project is also expected to involve the replacement of existing burners with ULNBs and these activities were not previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Thus, this SEA updates the previous air quality and GHG emission impacts analysis conducted in the December 2015 Final PEA for NOx RECLAIM to reflect these changes.

4.2.0 Introduction

The proposed project applies to 16 petroleum refineries and facilities with related operations to petroleum refineries, and their associated combustion equipment. As previously summarized in Table 4.1-1, there are multiple options available to achieve BARCT depending on the category of combustion equipment. The December 2015 Final PEA for NOx RECLAIM, upon which this SEA relies, analyzed the environmental impacts from installing new or modifying existing SCRs, installing LoTOx™ with and without WGS, and installing UltraCat™ with DGS on various combustion equipment operating at nine refineries. The proposed project applies to the same nine refineries that were analyzed in the December 2015 Final PEA for NOx RECLAIM plus an additional seven refineries for the same BARCT control equipment.

In addition to these BARCT compliance options considered in the December 2015 Final PEA for NOx RECLAIM, the analysis of the proposed project in this SEA also includes the replacement of burners with ULNBs, which is a new method to achieve BARCT in PR 1109.1. Table 4.2-1 lists the estimated number of air pollution control devices analyzed per equipment category and the number of affected refinery facilities in the December 2015 Final PEA for NOx RECLAIM. Table 4.2-2 lists those estimated numbers for PR 1109.1. Nine of the 11 facilities that require modifications as a result of PR 1109.1 were analyzed previously under NOx RECLAIM. Table

4.2-3 lists the estimated number of control devices that may be installed in order to implement PR 1109.1 but that were not previously analyzed under NOx RECLAIM.

Table 4.2-1
Estimated Number of NOx Air Pollution Control Devices Per Equipment Category for 11 Refineries Analyzed in the December 2015 Final PEA for NOx RECLAIM

Equipment Category	Number of Affected Facilities	Estimated Number of Air Pollution Control Devices Analyzed in the December 2015 Final PEA for NOx RECLAIM
Refinery Process Heaters and Boilers	8	73 New SCRs
SRU/TGs	5	5 LoTOx™ with WGSs 1 New SCR
FCCUs	5	2 New SCRs 1 LoTOx™ with WGS 1 LoTOx™ without WGS
Refinery Gas Turbines	5	7 New SCRs
Petroleum Coke Calciner	1	1 LoTOx™ with WGS, or 1 UltraCat™ with DGS
.	**TOTAL**	**83 New SCRs*** **1 LoTOx™ without WGS** **7 LoTOx™ with WGSs or** **6 LoTOx™ with WGSs and 1 UltraCat™ with DGS**

* The December 2015 Final PEA for NOx RECLAIM analyzed potential upgrades to existing SCRs, but for the purposes of conducting a worst-case analysis, the environmental impacts associated with installing a new SCR were also applied to the analysis for upgrading an existing SCR.

Table 4.2-2
Estimated Number of NOx Air Pollution Control Devices Per Equipment Category for 16 Refineries subject to PR 1109.1

Equipment Category	Number of Affected Facilities	Estimated Number of Air Pollution Control Devices for PR 1109.1
Refinery Process Heaters and Boilers	9	~~71~~ 76 New SCRs ~~11~~ 8 SCR Upgrades ~~59~~ 47 Burner Replacements with ULNBs 9 Heater/Boiler Replacements
SRU/TGs	6	9 Burner Replacements with ULNBs
FCCUs	2	2 New SCRs, or 1 New SCR and 1 LoTOx™ with WGS
Thermal Oxidizers	4	8 Burner Replacements with ULNBs
Refinery Gas Turbines	2	5 SCR Upgrades
Petroleum Coke Calciner	1	1 New SCR, 1 LoTOx™ with WGS, or 1 UltraCat ™ with DGS
	TOTAL	**~~72~~ 77 to ~~74~~ 79 New SCRs** **~~16~~ 13 SCR Upgrades** **0 to 2 LoTOx™ with WGS** **0 to 1 UltraCat™ with DGS** **~~76~~ 64 Burner Replacements with ULNBs** **9 Heater/Boiler Replacements**

Table 4.2-3
Estimated Number of NOx Air Pollution Control Devices Per Equipment Category for 16 Refineries subject to PR 1109.1 Not Previously Analyzed Under NOx RECLAIM

Equipment Category	Number of Affected Facilities	Estimated Number of Air Pollution Control Devices Not Previously Analyzed in the December 2015 Final PEA for NOx RECLAIM
Refinery Process Heaters and Boilers	9	~~59~~ 47 Burner Replacements with ULNBs ~~20~~ 25 New SCRs ~~6~~ 3 SCR Upgrades 9 Heater/Boiler Replacements
SRU/TGs	4	5 Burner Replacements with ULNBs
Thermal Oxidizers	4	8 Burner Replacements with ULNBs
Refinery Gas Turbines	1	1 SCR Upgrade
	TOTAL	**~~20~~ 25 New SCRs** **~~7~~ 4 SCR Upgrades** **~~72~~ 60 Burner Replacements with ULNBs** **9 Heater/Boiler Replacements**

* The differences in the number of affected facilities per equipment category and the estimated number of air pollution control devices in Tables 4.2-1 to 4.2-3 are attributable to the completed installation of some NOx control devices during the previous six years and cases where the air pollution control device analyzed in the December 2015 Final PEA for NOx RECLAIM demonstrated greater emissions when compared to air pollution control devices that could be installed in order to comply with PR 1109.1. For example, if a SRU/TG was analyzed in the December 2015 Final PEA for NOx RECLAIM to be modified with a LoTOx™ with WGS, no control was installed in the previous six years, and the same SRU/TG is analyzed under PR 1109.1 for burner replacement with ULNBs, because the emissions associated with installing a LoTOx™ with WGS are much greater than those for ULNB replacement, the emissions impact associated with installing

a ULNB for PR 1109.1 is considered to have been over estimated through the analysis in the December 2015 Final PEA for NOx RECLAIM and is not included in Table 4.2-3.

In general, the environmental analysis assumes that the air pollution control technologies for the affected combustion sources, if employed, will reduce NOx emissions overall. However, construction activities associated with the installation of new air pollution control devices, the modification of existing control devices, and the replacement of burners will create secondary air quality impacts (e.g., emissions), which can adversely affect local and regional air quality during the construction period.

Emissions may be generated during construction as well as after construction is completed when the equipment is operating. During construction, emissions may be generated by construction equipment and by vehicles used for worker commuting, and transporting construction supplies and hauling waste. After construction activities are completed, emissions may be generated directly by the operation of the add-on air pollution control devices (as GHGs from electricity or fuel use) and vehicles used for delivering fresh materials needed for equipment maintenance (e.g., chemicals, fresh catalyst, etc.) and hauling away solid waste for disposal or recycling (e.g., spent catalyst). The analysis of operational impacts is also provided in Section 4.2.2. Refer to Appendix C for the detailed calculations used to estimate secondary construction- and operational-related air quality impacts.

One key difference between the analysis in the December 2015 Final PEA for NOx RECLAIM and this SEA, is that the California Emissions Estimator Model® (CalEEMod®) was not utilized to calculate the emissions for the refinery sector in December 2015 Final PEA for NOx RECLAIM..

CalEEMod® is a statewide land use emissions computer model designed to provide a uniform platform for government agencies and other entities to quantify potential criteria pollutant and GHG emissions associated with both construction and operations from a variety of projects. The model has the ability to quantify direct emissions from construction and operation activities, including vehicle use, as well as indirect emissions, such as GHG emissions from energy use and water use. Further, the model identifies mitigation measures which can be applied to reduce criteria pollutant and GHG emissions, as applicable. In particular, CalEEMod® is designed to adjust the PM10 and PM2.5 emissions to account for reducing fugitive dust via watering in accordance with South Coast AQMD Rule 403. However, CalEEMod® does not have a land use option that is suitable for estimating construction and operation emissions for projects located at large industrial facilities like refineries. While CalEEMod® has a user-defined option which allows the modeler to override some of the default data and instead input customized parameters such as specific and varying construction equipment operating during multiple construction phases with varying construction hours, the model does not have the ability to customize or quantify operational impacts from activities other than mobile sources such as electricity and chemicals that are needed to operate the air pollution control equipment. To avoid underestimating emissions which would occur from these additional operational activities, the emission calculations conducted for the refinery-sector facilities were prepared using excel spreadsheets, in lieu of CalEEMod®, and relied upon known emission factors and other data that was available at the time of publication.

One other helpful mitigation module in CalEEMod® is the ability to mitigate or adjust the emissions from construction equipment that is rated at 50 horsepower (hp) or greater to apply the emission factors for Tier 4 Final off-road equipment. This module in CalEEMod® is consistent with the mitigation measure AQ-5 that was previously adopted in the Findings, Statement of

Overriding Considerations, and Mitigation Monitoring Plan for the December 2015 Final PEA for NOx RECLAIM[3] which states:

> AQ-5 All off-road diesel-powered construction equipment greater than 50 hp shall meet Tier-4 off-road emission standards at a minimum. In addition, if not already supplied with a factory-equipped diesel particulate filter, all construction equipment shall be outfitted with BACT devices certified by CARB. Any emissions control device used by the contractor shall achieve emissions reductions that are no less than what could be achieved by a Level 3 diesel emissions control strategy for a similarly sized engine as defined by CARB regulations. Construction equipment shall incorporate, where feasible, emissions-reducing technology such as hybrid drives and specific fuel economy standards. In the event that any equipment required under this mitigation measure is not available, the project proponent shall provide documentation in the Construction Emissions Management Plan or associated subsequent status reports as information becomes available.

A brief note: the use of Tier 4 Final off-road equipment is a mitigation measure that applies to all projects evaluated in this SEA. One other mitigation measure: dust suppression by watering, will apply only the installation of new SCRs with associated ammonia storage tanks, and will be discussed later in that corresponding section. Thus, for the analysis in this SEA, CalEEMod® version 2016.3.2. was utilized to estimate the construction emissions associated with the installations of the various air pollution control devices that may occur for the proposed project as well as the mobile source emissions from operational activities that may occur after construction is completed. In addition, whenever there is soil disturbance and the potential to generate fugitive dust during construction, the fugitive dust component of the PM10 and PM2.5 emissions reflect the adjustment to account for watering in accordance with South Coast AQMD Rule 403 and are identified as mitigated emissions in the summary tables. Similarly, the mitigated construction emissions presented in this chapter reflect the application of the mitigation calculation for all construction equipment rated 50 hp and greater that are projected to be utilized for this project.

It is important to note that for some equipment categories, the December 2015 Final PEA for NOx RECLAIM analyzed the environmental impacts from deploying air pollution control devices which resulted in more emissions during construction than what would otherwise occur from installing different types of air pollution control devices for the equivalent equipment categories under the proposed project. In the event that the currently proposed project may identify a different air pollution control approach for the same equipment category that result in fewer emissions impacts when compared to the emissions impacts in impacts previous analysis in the December 2015 Final PEA for NOx RECLAIM, this SEA will default to the previous analysis, which is more conservative. Conversely, if the currently proposed project identifies a different air pollution control approach for the same equipment category that result in greater emissions impacts when compared to the emissions impacts in impacts previously analyzed in the December 2015 Final PEA for NOx RECLAIM, this SEA will reflect the updated emissions data. This approach will ensure that the emissions presented in this SEA do not reflect any double counting from the

[3] South Coast AQMD, Attachment 1 to the Governing Board Resolution for the Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), Findings, Statement of Overriding Considerations and Mitigation Monitoring Plan. December 2015. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2015/regxxfindings.pdf

previous analysis in December 2015 Final PEA for NOx RECLAIM while also not underestimating the emissions that may result from the proposed project.

4.2.1 Significance Criteria

To determine whether air quality and GHG impacts from adopting and implementing the proposed project are significant, impacts will be evaluated and compared to the significance criteria on the following page. The significance thresholds for criteria pollutant emissions: the mass daily thresholds, were developed in 1993, and a full discussion can be found in the South Coast AQMD CEQA Handbook. Significance thresholds for toxic air contaminants and odor are based on requirements under Rules 1401 and 212, and 402 respectively. The significance threshold for greenhouse gas emissions was most recently updated in December 2008 when the Governing Board approved an interim GHG significance threshold for projects where the South Coast AQMD is lead agency. There has been ongoing development of the significance thresholds, and detailed discussion is available on the South Coast AQMD website.[4] All feasible mitigation measures will be identified in Section 4.2.2 and implemented to reduce any identified significant impacts to the maximum extent feasible. Significance determinations for construction impacts are based on the maximum or peak daily emissions during the construction period, which provides a "worst-case" analysis of the construction emissions. Similarly, significance determinations for operational emissions are based on the maximum or peak daily emissions during the operational phase.

The proposed project will have significant adverse air quality impacts if any one of the thresholds in Table 4.2-4 are equaled or exceeded.

[4] http://www.aqmd.gov/home/rules-compliance/ceqa/air-quality-analysis-handbook

Table 4.2-4
South Coast AQMD Air Quality Significance Thresholds

Mass Daily Thresholds [a]		
Pollutant	**Construction [b]**	**Operation [c]**
NO_x	100 lbs/day	55 lbs/day
VOC	75 lbs/day	55 lbs/day
PM_{10}	150 lbs/day	150 lbs/day
$PM_{2.5}$	55 lbs/day	55 lbs/day
SO_x	150 lbs/day	150 lbs/day
CO	550 lbs/day	550 lbs/day
Lead	3 lbs/day	3 lbs/day
Toxic Air Contaminants (TACs), Odor, and GHG Thresholds		
TACs (including carcinogens and non-carcinogens)	Maximum Incremental Cancer Risk ≥ 10 in 1 million Cancer Burden > 0.5 excess cancer cases (in areas ≥ 1 in 1 million) Chronic & Acute Hazard Index ≥ 1.0 (project increment)	
Odor	Project creates an odor nuisance pursuant to South Coast AQMD Rule 402	
GHG	10,000 MT/yr CO_2eq for industrial facilities	
Ambient Air Quality Standards for Criteria Pollutants [d]		
NO_2 1-hour average annual arithmetic mean	South Coast AQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 0.18 ppm (state) 0.03 ppm (state) and 0.0534 ppm (federal)	
PM_{10} 24-hour average annual average	10.4 $\mu g/m^3$ (construction)[e] & 2.5 $\mu g/m^3$ (operation) 1.0 $\mu g/m^3$	
$PM_{2.5}$ 24-hour average	10.4 $\mu g/m^3$ (construction)[e] & 2.5 $\mu g/m^3$ (operation)	
SO_2 1-hour average 24-hour average	0.25 ppm (state) & 0.075 ppm (federal – 99th percentile) 0.04 ppm (state)	
Sulfate 24-hour average	25 $\mu g/m^3$ (state)	
CO 1-hour average 8-hour average	South Coast AQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 20 ppm (state) and 35 ppm (federal) 9.0 ppm (state/federal)	
Lead 30-day Average Rolling 3-month average	1.5 $\mu g/m^3$ (state) 0.15 $\mu g/m^3$ (federal)	

[a] Source: South Coast AQMD CEQA Handbook (South Coast AQMD, 1993)
[b] Construction thresholds apply to both the South Coast Air Basin and Coachella Valley (Salton Sea and Mojave Desert Air Basins).
[c] For Coachella Valley, the mass daily thresholds for operation are the same as the construction thresholds.
[d] Ambient air quality thresholds for criteria pollutants based on South Coast AQMD Rule 1303, Table A-2 unless otherwise stated.
[e] Ambient air quality threshold based on South Coast AQMD Rule 403.

KEY: lbs/day = pounds per day; ppm = parts per million; $\mu g/m^3$ = microgram per cubic meter; ≥ = greater than or equal to; MT/yr CO_2eq = metric tons per year of CO_2 equivalents; > = greater than

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4.2.2 Potential Air Quality Impacts and Mitigation Measures

4.2.2.1 Project-Specific Air Quality Impacts During Construction

Construction-related emissions can be distinguished as either onsite or offsite. Onsite emissions generated during construction principally consist of exhaust emissions (NOx, SOx, CO, VOC, PM2.5 and PM10) from heavy-duty construction equipment operation, fugitive dust (primarily as PM10) from disturbed soil, and VOC emissions from asphaltic paving and painting. Offsite emissions during the construction phase normally consist of exhaust emissions and entrained paved road dust (primarily as PM10) from worker commute trips, material delivery trips, and haul truck material trips to and from the construction site.

In the December 2015 Final PEA for NOx RECLAIM analysis, the space limitations within each affected facility were evaluated and each facility was determined to have sufficient space to install new NOx air pollution control equipment or modify existing NOx air pollution control equipment. However, because installation of larger NOx air pollution control equipment may need to occupy the space of previous equipment, demolition activities were assumed to occur prior to the equipment installation to remove any existing equipment or structures (as applicable), remove the old piping and electrical connections, and break up the old foundation with a demolition hammer. For these reasons, digging, earthmoving, grading, slab pouring, or paving activities are anticipated and were analyzed. The amount of plot space that may be needed to install one or more NOx air pollution control devices at any of the affected facilities would not exceed one acre; therefore, no more than one acre of area would need to be disturbed at a single facility at a given time. Construction was assumed to consist of two phases: 1) demolition and 2) construction to install the air pollution control devices units along with supporting devices and structures. In addition, for facilities that will need to install tanks to store ammonia to support the operation of SCR or UltraCat™ with DGS, a site preparation phase was also included to account for building a containment berm as part of installing an ammonia storage tank.

The type of construction-related activities attributable to installing new NOx air pollution control equipment or modifying existing NOx air pollution control equipment would consist predominantly of deliveries of steel, piping, wiring, chemicals, catalysts, and other materials, and would also involve maneuvering the materials within the site via a variety of off-road and on-road equipment such as a crane, forklift, et cetera or haul truck, respectively. If a new foundation is not needed, to establish footings or structure supports, some concrete cutting and digging may be necessary in order to re-pour new footings prior to building above the existing foundation.

From a construction point of view, the installation of a NOx air pollution control technology at a refinery is a complex process. For example, if a facility operator chooses to install NOx air pollution control equipment, time will be needed for pre-construction/advance planning activities such as engineering analysis of the affected equipment; engineering design of the potential control equipment; contracting with a vendor; securing financing, ordering, and purchasing the equipment; obtaining permits and clearances; and scheduling contractors and workers.

In the December 2015 Final PEA for NOx RECLAIM, the analysis assumed that the amount of lead time would vary from six months (e.g., for a SCR for refinery/boiler heater or gas turbine) to up to 18 months for a scrubber (either a WGS or DGS). Then to physically build the equipment, an additional six to 18 months would be needed. For example, six months would be needed to construct one SCR for one refinery boiler, heater, or gas turbine, 12 months would be needed to construct a SCR for a FCCU, and up to 18 months would be needed to construct a scrubber (either a WGS or DGS). These assumptions have been applied to the construction analysis for the proposed project. In addition, since the proposed project would also involve the replacement of burners with ULNBs which was not previously analyzed in the December 2015 Final PEA for NOx RECLAIM, this SEA includes the following additional construction analysis associated with burner replacements, as described in the following section.

Replacement of Existing Burners with ULNBs

As presented in Tables 4.2-2 and 4.2-3, the proposed project identified several equipment categories which are anticipated to replace the burners in the combustion devices with ULNBs and these equipment categories are fired by refinery fuel gas. ULNBs are more sensitive than traditional burners in that they have smaller port tips which may plug from moisture and particulates. To ensure each ULNB performs consistently and reliably, incoming fuel gas will need an additional pre-cleaning step. Therefore, installation of a refinery fuel gas filter system is also expected when replacing burners with ULNBs. The refinery fuel gas filter system includes a fuel coalescer vessel and other parts which are usually pre-built at the factory and brought on site; the size and design varies according to the amount of refinery fuel gas that needs to be treated. Refinery fuel gas filter systems are not unique to ULNBs, and are typically utilized wherever filtered refinery fuel gas is required. Some of the affected facilities subject to the proposed project may already have existing refinery fuel gas filter systems, so the assumption to include a fuel gas filter system with each burner replacement project is more conservative.

The fuel coalescer vessel is typically located adjacent to the respective heater, boiler, or combustion equipment, and the foundation of the refinery fuel gas filter system has a footprint of approximately 10 feet by 10 feet. So that worst case impacts are considered, this analysis assumes that there is an existing refinery fuel gas filter system that needs to be removed, and that the demolition of the existing fuel gas filter system will occur concurrently with the replacement of 100 burners with 100 ULNBs in the combustion equipment. The maximum duration of burner replacement and ULNB installation is assumed to be three months of continuous construction work (24 hours per day, seven days per week).

Five construction phases were assumed for the analysis of activities associated with replacing burners with ULNBs and installing a refinery fuel gas filter system:

- Installation of scaffolding,
- Replacement of burners with ULNBs,
- Demolition of existing fuel coalescer vessel,
- Pour foundation for new fuel coalescer vessel, and
- Installation of new fuel coalescer vessel.

Construction emissions associated with replacing burners with ULNBs for one combustion device at one facility were estimated using the California Emission Estimator Model (CalEEMod®), version 2016.3.2. Construction equipment and construction schedule were estimated based on South Coast AQMD's consultation with a representative from John Zink Company, a manufacturer of ULNB technology for refinery combustion equipment.

Table 4.2-5
Construction Equipment Needed to Replace Existing Burners with ULNBs for One Combustion Device

Construction Phase	Off-Road Equipment Type	Quantity	Daily Usage Hours
Installation of Scaffolding	Forklifts	1	12
Replacement of Burners with ULNBs	Air Compressors	1	24
	Cranes	1	24
	Forklifts	1	24
	Generator Sets	1	24
	Tractors/Loaders/Backhoes	1	2
Demolition of Existing Fuel Coalescer Vessel	Cranes	1	12
	Forklifts	1	12
	Tractors/Loaders/Backhoes	1	12
	Generator Sets	1	12
	Air Compressors	1	12
Pour foundation for New Fuel Coalescer Vessel	Cement and Mortar Mixers	1	4
	Off-Highway Trucks	1	4
Installation of New Fuel Coalescer Vessel	Air Compressors	1	13
	Bore/Drill Rigs	1	12
	Cranes	1	12
	Forklifts	1	12
	Tractors/Loaders/Backhoes	2	12
	Welders	1	12

Tables 4.2-6 and 4.2-7 present the unmitigated and mitigated peak daily construction emissions, respectively, from replacing the existing burners with ULNBs for one combustion device and installing the fuel gas filter system. The CalEEMod® output files for the annual, summer, and winter construction emissions can be found in Appendix B; the peak daily emissions below are the greater of maximum daily emissions for each criteria pollutant between the summer and winter files. The unmitigated and mitigated peak daily construction emissions are less than the South Coast AQMD's air quality significance thresholds for construction.

Table 4.2-6
Unmitigated Peak Daily Construction Emissions from Replacing Burners with ULNBs for One Combustion Device

Unmitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Replacement of Burners with ULNBs	6.5	61.4	51.3	0.1	3.6	3.0
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

Table 4.2-7
Mitigated Peak Daily Construction Emissions from Replacing Burners with ULNBs for One Combustion Device

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Replacement of Burners with ULNBs	1.8	9.4	58.8	0.1	0.8	0.4
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

The data presented in Tables 4.2-6 and 4.2-7 reflect the construction emissions associated with installing ULNBs on one piece of combustion equipment. However, if burners are replaced with ULNBs for 10 or more pieces of combustion equipment concurrently, either at one facility or multiple facilities, which is possible, then the South Coast AQMD air quality significance threshold for NOx and CO could be exceeded and mitigation measures would be required. A discussion of mitigation measures is provided in Section 4.2.4.

Installation of New SCR System and New Ammonia Storage Tank for Boilers, Heaters, or Gas Turbines

The December 2015 Final PEA for NOx RECLAIM previously estimated construction impacts associated with the installation of a new SCR and one new ammonia storage tank for one boiler, process heater, or gas turbine in the following spreadsheets which are located in Appendix E of December 2015 Final PEA for NOx RECLAIM: "Construction of 1 SCR for Refinery Boiler, Process Heater, or Gas Turbine," "Construction of 1 Berm for 1 Aqueous Ammonia Storage Tank," and "Offsite Consequence Analysis for Aqueous Ammonia Spill at a Refinery." The analysis in this SEA relies upon these previous assumptions such that the same construction equipment will be utilized, and the same construction timing, the same number of trips and vehicle miles traveled (VMT), the same mitigation measures for watering the affected areas will be applied, and the same installation of an 11,000-gallon ammonia storage tank plus containment berm will be needed for each SCR. However, the calculations for the SCR construction scenario in this SEA have been updated to utilize CalEEMod® version 2016.3.2, which has updated emission factors for the construction equipment and mobile sources and also includes mitigated calculations based on watering to control fugitive dust per South Coast AQMD Rule 403 and the additional mitigation measure that is built into CalEEMod® which requires all construction equipment rated at 50 hp or higher to be Tier 4 Final.

Table 4.2-8 lists the construction equipment required for installation of a new SCR for one boiler, heater, or gas turbine.

Table 4.2-8
Construction Equipment Needed to Install One New SCR for One Boiler, Heater, or Gas Turbine

Off-Road Equipment Type	Quantity	Daily Usage Hours
Cranes	1	8
Welders	2	8
Air Compressors	1	1
Tractors/Loaders/Backhoes	1	4
Plate Compactors	1	4
Forklifts	1	3
Pumps	1	2
Concrete/Industrial Saws	1	2
Generator Sets	1	8
Aerial Lifts	1	2

Source: Table 4.2-7 of the December 2015 Final PEA for NOx RECLAIM

In order to account for the fugitive PM10 emissions and mitigation with using water for dust suppression from the construction of the ammonia tank and containment berm which were calculated in the "Construction of 1 Berm for 1 Aqueous Ammonia Storage Tank" excel spreadsheet into CalEEMod®, the following updates were made to the analysis: 1) an off-highway truck was added to incorporate emissions that would occur from the movement of the water truck; 2) a rubber tired dozer was added but had zero usage hours (to account for the dust associated with material movement in CalEEMod® without adding emissions from the rubber tired dozer, since a different piece of construction equipment already accounts for the emissions from the construction equipment engine, 3) the size of the area to be disturbed for the footprint of each ammonia storage tank was increased from 400 to 539 square feet; and 4) the grading assumed a cut of three feet in depth for the entire plot which would create one ton of soil to be hauled away.

Tables 4.2-9 and 4.2-10 present the unmitigated and mitigated peak daily construction emissions, respectively, from installing one new SCR for one boiler, heater, or gas turbine and one new ammonia storage tank for the proposed project. For comparison, the original emission estimates from the December 2015 Final PEA for NOx RECLAIM analysis are also included. The CalEEMod® output files for the annual, summer, and winter construction emissions can be found in Appendix B; the peak daily emissions below are the greater of maximum daily emissions for each criteria pollutant between the summer and winter files.

Table 4.2-9
Unmitigated Peak Daily Construction Emissions from Installing One New SCR System for One Boiler, Heater, or Gas Turbine and One New Ammonia Storage Tank at One Facility

Unmitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Proposed Project: One New SCR and Ammonia Tank Installation	2.12	14.80	16.77	0.03	1.72	1.00
South Coast AQMD Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**
December 2015 Final PEA for NOx RECLAIM: One New SCR and Ammonia Tank Installation	3.92	21.07	20.87	0.04	48.30	48.61
South Coast AQMD Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

Table 4.2-10
Mitigated Peak Daily Construction missions from Installing One New SCR System for One Boiler, Heater, or Gas Turbine and One New Ammonia Storage Tank at One Facility

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Proposed Project: One New SCR and One New Ammonia Tank Installation	1.16	5.72	17.12	0.03	1.13	0.44
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**
December 2015 Final PEA for NOx RECLAIM: One New SCR and One New Ammonia Tank Installation	3.92	21.07	20.87	0.04	19.45	19.76
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

The data presented in Tables 4.2-9 and 4.2-10 reflect the construction emissions associated with installing one SCR and one ammonia storage tank for one piece of combustion equipment. However, if more than 17 SCRs and the associated ammonia storage tanks are concurrently installed at multiple facilities, which is possible, then the South Coast AQMD air quality significance threshold for NOx could be exceeded and mitigation measures would be required. A discussion of mitigation measures is provided in Section 4.2.4.

Installation of New SCR System and New Ammonia Storage Tank and/or Installation of LoTOx^{TM} with WGS for FCCUs

For the FCCU equipment category, the December 2015 Final PEA for NOx RECLAIM previously identified five FCCUs that would need to be retrofitted with two SCRs and three LoTOx^{TM} with and without a WGS. However, in 2017, one FCCU which was originally identified to install LoTOx^{TM} with a WGS, was shutdown. Under the currently proposed project, the BARCT analysis revealed that only two FCCUs may require the installation of air pollution control equipment, with either: 1) one new SCR and one new ammonia storage tank installed for both FCCUs; or 2) one new SCR and one new ammonia storage tank installed for one FCCU and one LoTOx^{TM} with WGS for the other FCCU. The remaining two FCCU currently meet the conditional NOx limits under PR 1109.1 and will not require control modification.

The December 2015 Final PEA for NOx RECLAIM previously estimated construction impacts associated with the installation of a new SCR and new ammonia storage tank for one FCCU in the following spreadsheets which are located in Appendix E of December 2015 Final PEA for NOx RECLAIM: "Construction of 1 SCR for 1 FCCU," "Construction of 1 Berm for 1 Aqueous Ammonia Storage Tank," and "Offsite Consequence Analysis for Aqueous Ammonia Spill at a Refinery." The analysis in this SEA relies upon the previous assumptions such that the same construction equipment will be utilized with the same construction timing, the same number of trips and VMT, the same mitigation measures for watering the affected areas will be applied, and the same installation of an 11,000-gallon ammonia storage tank plus containment berm be needed for each SCR. However, the calculations for the SCR construction scenario in this SEA have been updated to utilize CalEEMod® version 2016.3.2, which has updated emission factors for the construction equipment and mobile sources and also includes mitigated calculations based on watering to control fugitive dust per South Coast AQMD Rule 403 and the additional mitigation measure that is built into CalEEMod® which requires all construction equipment rated at 50 hp or higher to be Tier 4 Final.

Table 4.2-11 lists the construction equipment required for installation of a new SCR and ammonia tank for one FCCU.

Table 4.2-11
Construction Equipment That May Be Needed to Install One New SCR and One New Ammonia Storage Tank for One FCCU

Off-Road Equipment Type	Quantity	Daily Usage Hours
Cranes	1	8
Rough Terrain Cranes[a]	1	8
Welders	5	8
Air Compressors	1	8
Tractors/Loaders/Backhoes	1	8
Plate Compactors	1	2
Forklifts	1	6
Pumps	1	2
Concrete/Industrial Saws	1	2
Generator Sets	2	8

[a] Table 4.2-8 of the December 2015 Final PEA for NOx RECLAIM lists 1 Crane and 1 Rough Terrain Crane (28 ton); therefore, two cranes are included in the analysis for this SEA.

In order to account for the fugitive PM10 emissions from the construction of the ammonia tank and containment berm into CalEEMod®, the following updates were made to the analysis: 1) an off-highway truck was added to incorporate emissions that would occur from the movement of the water truck; 2) a rubber tired dozer was added but had zero usage hours (to account for the dust associated with material movement in CalEEMod® without adding emissions from the rubber tired dozer, since a different piece of construction equipment already accounts for the emissions from the construction equipment engine, 3) the size of the area to be disturbed for the footprint of each ammonia storage tank was increased from 400 to 539 square feet; and 4) the grading assumed a cut of three feet in depth for the entire plot which would create one ton of soil to be hauled away.

Tables 4.2-12 and 4.2-13 present the unmitigated and mitigated peak daily construction emissions, respectively, from installing one new SCR and one new ammonia storage tank for one FCCU for the proposed project. For comparison, the original emission estimates from the December 2015 Final PEA for NOx RECLAIM analysis are also included. The CalEEMod® output files for the annual, summer, and winter construction emissions can be found in Appendix B; the peak daily emissions below are the greater of maximum daily emissions for each criteria pollutant between the summer and winter files.

Table 4.2-12
Unmitigated Peak Daily Construction Emissions from Installing One New SCR and One New Ammonia Storage Tank for One FCCU

Unmitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Proposed Project: One New SCR and One New Ammonia Storage Tank Installation	6.21	33.86	48.68	0.11	7.17	3.07
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**
December 2015 Final PEA for NOx RECLAIM: One New SCR and One New Ammonia Tank Installation	10.03	41.26	66.21	0.14	50.30	49.30
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

Table 4.2-13
Mitigated Peak Daily Construction Emissions from Installing One New SCR and One New Ammonia Storage Tank for One FCCU

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Proposed Project: One New SCR and One New Ammonia Storage Tank Installation	4.11	12.81	51.00	0.11	5.98	1.94
South Coast AQMD Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**
December 2015 Final PEA for NOx RECLAIM: One New SCR and One New Ammonia Tank Installation	10.03	41.26	66.21	0.14	21.45	20.45
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

The data presented in Tables 4.2-12 and 4.2-13 reflect the unmitigated and mitigated construction emissions associated with installing one new SCR and one new ammonia storage tank for one FCCU. In the event that both facilities with FCCUs concurrently install each SCR and the associated ammonia storage tank, none of the South Coast AQMD air quality significance threshold for construction would be exceeded. However, since control equipment for other types of sources may also be installed during the same time frame, peak daily construction impacts would remain potentially significant for all the above-listed pollutants.

The December 2015 Final PEA for NOx RECLAIM also previously estimated construction impacts associated with the installation of one LoTOx^{TM} with WGS for two FCCUs in the following spreadsheets which are located in Appendix E of December 2015 Final PEA for NOx RECLAIM: “Facility 4” and “Facility 9.” Table 4.2-14 lists the construction equipment required for installation of a one LoTOx^{TM} with WGS. The analysis in this SEA relies upon the previous assumptions such that the same construction equipment will be utilized with the same construction timing, the same number of trips and VMT, the same mitigation measures for watering the affected areas will be applied.

Table 4.2-14
Construction Equipment That May Be Needed to Install One New LoTOx™ with Wet Gas Scrubber for One FCCU

Construction Phase	Off-Road Equipment Type	Amount	Daily Usage Hours
Demolition	Crane	1	8
Demolition	Front End Loader	1	8
Demolition	Forklift	1	8
Demolition	Concrete Saw	1	8
Demolition	Jack Hammer	1	8
Construction	Backhoe	1	8
Construction	Crane	2	8
Construction	Aerial Lift	3	8
Construction	Forklift	1	8
Construction	Generator	1	8
Construction	Welders	10	8
Construction	Cement Mixer	1	2

Source: See Table 4.2-9 of the December 2015 Final PEA for NOx RECLAIM.

Table 4.2-15 presents the mitigated peak daily construction emissions associated with installing one new LoTOx™ with WGS for one FCCU.

Table 4.2-15
Comparison of Mitigated Peak Daily Construction Emissions for Installing One LoTOx™ with WGS for One FCCU

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
December 2015 Final PEA for NOx RECLAIM: New LoTOx™ with WGS	36.13	103.55	233.38	0.20	30.40	12.21
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**YES**	**NO**	**NO**	**NO**	**NO**

When comparing Table 4.2-15 to Table 4.2-13, installing one LoTOx™ with WGS for one FCCU would result in more, and significant adverse construction emissions than to install one new SCR and one new ammonia storage tank for one FCCU. Further, because of the potential for both types of air pollution control equipment to be concurrently installed, significant and unavoidable adverse air quality impacts during construction are expected to occur and mitigation would be required.

Installation of New SCR System and New Ammonia Storage Tank and/or Installation of LoTOx™ with WGS for a Petroleum Coke Calciner

The December 2015 Final PEA for NOx RECLAIM previously identified one petroleum coke calciner located at one facility (identified as Facility 2) that would need to be retrofitted with one

LoTOx™ with WGS or one UltraCat™ with DGS. Under the currently proposed project, the BARCT analysis revealed that the petroleum coke calciner may also install one new SCR in lieu of either the one LoTOx™ with WGS or one UltraCat™ with DGS.

The December 2015 Final PEA for NOx RECLAIM previously estimated construction impacts associated with the installation of one LoTOx™ with WGS or one UltraCat™ with DGS in the "Facility 2" spreadsheet which is located in Appendix E of December 2015 Final PEA for NOx RECLAIM. The analysis in this SEA relies upon the previous assumptions such that the same construction equipment will be utilized with the same construction timing, the same number of trips and VMT, and the same mitigation measures for watering the affected areas will remain in place. It is assumed that, similar to an FCCU, installation of a new SCR for a petroleum coke calciner will result in less construction emissions as compared to installation of a new LoTOx™ with WGS or UltraCat™ with DGS. A more detailed discussion specific to Facility 2 is provided later in this chapter (see Section 4.2.2.3).

Upgrade of Existing SCR Systems

The December 2015 Final PEA for NOx RECLAIM conservatively estimated that construction impacts associated with upgrading an existing SCR would be the same as installing a new SCR but without the need to install a new ammonia storage tank. For the proposed project, this SEA contains a tailored analysis to specifically address SCR upgrades which is based on a previous analysis in the Final Mitigated Subsequent Environmental Assessment for Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities[5], but has been refined for a refinery setting.

Upgrade of an existing SCR system consists of catalyst replacement and additional ammonia injection. In order to gain access to the catalyst modules, a forklift will be needed to deliver and install scaffolding around the catalyst housing. To remove the spent catalyst modules and replace with fresh catalyst, one forklift, one aerial lift, and one crane are assumed to be needed. Adjustments to the ammonia injection grid typically do not require heavy construction equipment such that they would be modelled, and instead rely on smaller hand-held tools such as welding and cutting equipment to install regulating valves and mounting brackets. Since the SCR is part of an existing system with an existing ammonia storage tank, the construction analysis for SCR upgrades do not require any physical modifications to the existing ammonia tanks. Thus, construction impacts associated with upgrading existing SCRs are expected to be relatively minimal. Table 4.2-16 lists the construction equipment required for upgrade of one existing SCR system.

Table 4.2-16
Construction Equipment That May Be Needed to Upgrade One Existing SCR

Construction Phase	Off-Road Equipment Type	Quantity	Daily Usage Hours
Installation of Scaffolding	Forklifts	1	12
Catalyst Replacement	Aerial Lifts	1	12
	Cranes	1	12
	Forklifts	1	12

5 South Coast AQMD, Final Mitigated Subsequent Environmental Assessment for Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities, pg 2-11, October 2018. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2018/par-1135---final-mitigated-sea_with-appendices.pdf

Tables 4.2-17 and 4.2-18 present the unmitigated and mitigated peak daily construction emissions, respectively, from upgrading one SCR. The CalEEMod® output files for the annual, summer, and winter construction emissions can be found in Appendix B; the peak daily emissions below are the greater of maximum daily emissions for each criteria pollutant between the summer and winter files.

Table 4.2-17
Unmitigated Peak Daily Construction Emissions from Upgrading One SCR

Unmitigated Peak Daily Construction Emissions	**VOC (lb/day)**	**NOx (lb/day)**	**CO (lb/day)**	**SOx (lb/day)**	**PM10 (lb/day)**	**PM2.5 (lb/day)**
SCR Upgrade	0.96	10.73	7.1	0.02	0.69	0.47
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

Table 4.2-18
Mitigated Peak Daily Construction Emissions from Upgrading One SCR

Mitigated Peak Daily Construction Emissions	**VOC (lb/day)**	**NOx (lb/day)**	**CO (lb/day)**	**SOx (lb/day)**	**PM10 (lb/day)**	**PM2.5 (lb/day)**
One SCR Upgrade	0.29	2.79	8.28	0.02	0.41	0.12
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

The unmitigated and mitigated peak daily construction emissions are less than the South Coast AQMD's air quality significance thresholds for construction; however, if multiple SCR upgrades are conducted concurrently, which is possible, then the significance threshold for construction NOx may be exceeded and mitigation measures will be required. A discussion of cumulative mitigation measures is provided in Section 4.2.4. Nonetheless, even after mitigation is applied, significant and unavoidable adverse air quality impacts during construction is expected to occur since multiple facilities are expected to undergo construction to concurrently upgrade multiple existing SCRs.

Health Risk from Construction Activities

The projected increase in construction emissions from the proposed project was compared to the projected increase from a reference modeling case, using the Community Multiscale Air Quality (CMAQ) model, which evaluated larger NOx and PM2.5 emissions than would result from the proposed project. The increase in PM2.5 resulting from the reference case was reduced by a ratio of the amount of the reference case emissions to the proposed project emissions, assuming that one-fourth of the construction emissions would happen at any given time. This assumption is based on the fact that construction would occur in three separate phases under the proposed project, and could occur over a period as long as six years for the first phase, if the first phase construction is completed by 2028, which is the best estimate available. This method resulted in a projected change in PM2.5 concentration from the proposed project. The reference case used 3,059 pounds per day of NOx and 153 pounds per day of PM2.5, whereas the proposed project would result in a total of 873 pounds per day of NOx and 52 pounds per day of PM2.5. One-fourth of the construction emissions were used to conduct the analysis. The resulting change in concentration was up to 0.01 $\mu g/m^3$ at the maximum point and approximately 0.0006 $\mu g/m^3$ as the South Coast Air Basin average. These changes in concentration are so small that they are too close to the margin of error in the modeling to provide a meaningful result. Therefore, any increased adverse health effects associated with emissions during construction cannot be quantified accurately, but the difference between conditions with the proposed project and without the proposed project is essentially within the margin of error.

Health Risk from Exhaust of Diesel Particulate Matter from Construction Equipment

Construction duration for the proposed project and under the December 2015 Final PEA for NOx RECLAIM is assumed to be a maximum of three months for replacement of burners with ULNB; one year for installation of a new SCR and ammonia tank for a boiler, heater, or gas turbine; two years for installation of a new SCR and ammonia tank for a FCCU; and three years for installation of either a WGS or DGS scrubber. Diesel particulate matter, emitted from the exhaust of diesel-fueled construction equipment during these periods, is a TAC causing health risk. However, OEHHA recommends that calculation of individual cancer risk for a residential receptor utilize a 30 or 70 year exposure and for a worker receptor, 25 years; therefore, health risk from construction cannot be quantified.

4.2.2.2 Project-Specific Air Quality Impacts During Operation

PR 1109.1

Emissions may be generated by the operation of the new or upgraded air pollution control devices (as GHGs) due to increased electricity and water use (only for WGSs), increased wastewater disposal (only for LoTOx™ with WGSs), and amortized GHG emissions from construction. In addition, emissions of criteria pollutants and GHGs may be generated from offsite vehicles used for delivering fresh materials needed for operations (e.g., chemicals, fresh catalyst, etc.) and for hauling away solid waste for disposal or recycling (e.g., spent catalyst). Finally, since SCR technology utilizes ammonia, a toxic air contaminant (TAC), some ammonia slip emissions are expected to occur during operation of SCR units. These ammonia emissions can react in the atmosphere to form PM2.5.

The operation of each air pollution control device that may be installed is also not expected to generate criteria pollutant emissions but rather to lessen the amount of NOx generated by the existing equipment/emission sources. However, secondary criteria pollutant emissions are expected to be generated as part of operation activities associated with operating and maintaining the air pollution control equipment after it is installed. In particular, the following activities may be sources of secondary criteria pollutant emissions during operation: 1) vehicle trips via heavy-duty trucks for periodic deliveries of ammonia primarily to operate new installations of SCRs and to a lesser extent, UltraCat™ with DGSs, sodium hydroxide (NaOH) for installations of LoTOx™ WGSs, hydrated lime for installations of UltraCat™ DGSs, and oxygen for installation of LoTOx™ units with or without WGSs; 2) vehicle trips via heavy-duty truck for periodic deliveries of catalyst and replacement filters as well as solid waste hauling of spent filters for each SCR unit installed; and 3) via heavy-duty truck hauling solid waste generated by each scrubber (WGS and DGS) installed.

As consolidated in Tables 4.2-1 to 4.2-3, operational impacts associated with all LoTOx™ WGS and UltraCat™ DGS projects resulting from the implementation of PR 1109.1 were previously analyzed in the December 2015 Final PEA for NOx RECLAIM, which is incorporated by reference. However, the analysis in this SEA will update the emissions estimates associated with new SCR operation and maintenance.

For any new construction of air pollution control equipment that utilizes ammonia, such as SCR technology, current South Coast AQMD policy does not allow the use of ~~anhydrous~~ ammonia at concentrations greater than 19% for new construction of a storage tank if the quantity capable of being stored is greater than 500 pounds or if the quantity is less than 500 pounds but there is a risk for an offsite consequence in the event of a tank failure. Existing storage tanks containing ammonia at concentrations greater than 19% may be used to service new installations of air pollution control equipment. To minimize the hazards associated with the use of ammonia, aqueous ammonia at a concentration of no more than 19 percent by weight (19% aqueous ammonia) is typically required as a permit condition associated with the installation of new SCR equipment. This policy is why the December 2015 Final PEA for NOx RECLAIM assumed that all ammonia utilized for new SCRs and UltraCat™ DGSs, would be 19% aqueous ammonia. Moreover, for the analysis in this SEA, in accordance with South Coast AQMD policy, the new SCRs are assumed to utilize 19% aqueous ammonia. However, any existing SCR which may undergo an upgrade would be expected to continue to utilize the same type of ammonia (e.g., anhydrous, 19% aqueous ammonia or some other concentration) and about the same quantity as it is currently using ~~if not less~~. The analysis also assumes that the existing ammonia storage tank for SCR upgrades will continue to provide the ammonia needed to continue operating the existing SCRs, without requiring any physical modifications. In the event that existing ammonia tanks are utilized for new installations of SCR, construction impacts would be less than assumed since the analysis assumed one new tank for each new SCR. Further, depending on the number of additional SCRs that would need to receive ammonia from an existing ammonia storage tank, the ammonia throughput limit on the permit may need to be revised. Increases of ammonia throughput for an existing tank would not be expected to change the existing risk associated with an offsite consequence in the event of a tank rupture.

The ammonia analysis in the December 2015 Final PEA for NOx RECLAIM assumed that each new SCR installation would also involve the installation of one new 11,000-gallon ammonia tank of 19% aqueous ammonia. Thus, all of the ammonia delivered to each facility would be 19% aqueous ammonia, which in turn, helped estimate the maximum number vehicle trips associated with ammonia deliveries. If a higher concentration of ammonia is currently being delivered to a facility for an existing ammonia storage tank that is intended to provide ammonia to new SCRs installed as part of the proposed project, the number of vehicle trips associated with higher concentrations of ammonia will be fewer than for those delivering 19% aqueous ammonia because less water is contained in the ammonia (e.g., 19% aqueous ammonia contains 81% water, 29% ammonia contains 71% water, and anhydrous ammonia contains no water).

The analysis in the December 2015 Final PEA for NOx RECLAIM assumed that 25-ton capacity trucks deliver fresh catalyst and haul spent catalyst once every five years, and that ammonia would be delivered via 7,000-gallon trucks per year. and this SEA applies these~~is~~ same assumptions in the updated analysis for the new SCRs that would be installed if the proposed project is implemented.

Secondary operational emissions were estimated using EMFAC2017 emission factors for heavy-heavy duty diesel-fueled trucks (EMFAC2011 vehicle code "T7" denotes heavy-heavy duty) for calendar year 2021. Based on the locations of disposal sites and chemical suppliers relative to the locations of the affected refineries, the analysis in this SEA assumes the same default round-trip truck distances that were assumed in the December 2015 Final PEA for NOx RECLAIM analysis, as follows: 100 miles for ammonia deliveries, 100 miles for fresh catalyst deliveries. For spent catalyst hauling, the analysis in the December 2015 Final PEA for NOx RECLAIM assumed 100 miles, but updated logistics information indicates that 130 miles is a more accurate mileage estimation. As such, the analysis in this SEA uses the updated mileage for calculating vehicle emissions during spent catalyst hauling.

Table 4.2-19
EMFAC2017 Emission Factors for T7 Diesel-Fueled Vehicles for Calendar Year 2021

Miles per Gallon	VOC (~~g~~lb/mi)	NOx (~~g~~lb/mi)	CO (~~g~~lb/mi)	SOx (~~g~~lb/mi)	PM10 (~~g~~lb/mi)	PM2.5 (~~g~~lb/mi)	CO2 (~~g~~lb/mi)	CH4 (~~g~~lb/mi)
6.51	2.24 E-04	8.39 E-03	9.54 E-04	3.00 E-05	1.14 E-04	1.09 E-04	3.18 E+00	1.06 E-05

Key: ~~g~~lb/mi – ~~grams~~ pounds per mile; CO2 = carbon dioxide; CH4 = methane

Emission sources associated with the operational-related activities as a result of implementing the proposed project may emit TACs. For example, as explained in Chapter 2 of this SEA, SCR and UltraCat™ DGSs utilize ammonia, a TAC, to reduce NOx emissions. Unreacted ammonia emissions generated from these units are referred to as ammonia slip. Ammonia slip is limited to five parts per million (ppm) by permit condition. Based on the June 2015 Staff Report for South Coast AQMD Rule 1401.1 – Requirements for New and Relocated Facilities Near Schools, and South Coast AQMD Rule 1402 – Control of Toxic Air Contaminants from Existing Sources, the concentration at a receptor located 25 meters from a stack would be much less than one percent of the concentration at the release from the exit of the stack. Thus, the peak concentration of ammonia at a receptor located 25 meters from a stack is calculated by assuming a dispersion of one percent. While ammonia does not have an OEHHA approved cancer potency value, it does have non-carcinogenic chronic (200 $\mu g/m^3$) and acute (3,200 $\mu g/m^3$) reference exposure levels (RELs). Table 4.2-20 summarizes the calculated non-carcinogenic chronic and acute hazard indices for ammonia and compared these values to the respective significance thresholds; both were shown to be less than significant.

Table 4.2-20
Health Risk from Refinery Facilities Using Ammonia

Ammonia Slip Concentration at the Exit of the Stack (ppm)	**Peak Concentration at a Receptor 25 m from the Stack** ($\mu g/m^3$)	**Acute REL** ($\mu g/m^3$)	**Chronic REL** ($\mu g/m^3$)	**Acute Hazard Index**	**Chronic Hazard Index**
5	35	3,200	200	**0.01**	**0.17**
		South Coast AQMD Health Risk Significance Threshold		**1.0**	**1.0**
		Exceed Significance?		**NO**	**NO**

Even if multiple SCRs are installed at one refinery facility, the locations of all the stacks would not be situated in the same place within the affected facility's property. As such, even with multiple SCR installations, the acute and chronic hazard indices would not be expected to exceed the significance threshold.

In summary, the operation of new SCR installations is expected to generate emissions from electricity, ammonia and fresh catalyst delivery, and spent catalyst haul-away. The operation of upgraded SCRs will not generate any new operational emissions because electricity and ammonia usage is expected to stay the same or less than baseline conditions , and catalyst delivery and haul-away is also expected to occur at the same frequency relative to baseline conditions.

In addition, diesel particulate matter from the exhaust of diesel-fueled heavy-duty trucks is also a TAC. The analysis estimates that a peak of 21 heavy-duty truck trips may occur at a single facility in one year (e.g., at Facility 6). Based on the 2016 CARB Airborne Toxic Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling, heavy-duty trucks are not expected to idle for more than five minutes per trip.[6] Therefore, up to 1.75 hours of idling may occur at a single facility. The weighted averaged of CARB emission factors for T7 vehicles using diesel fuel is 0.05 grams per hour of diesel particulate matter. Therefore, a peak of 8.74×10^{-8} ton of diesel particulate exhaust per year would be generated at one refinery facility. Based on the Tier II methodology described in the South Coast AQMD Risk Assessment Procedures for Rules 1401, 1401.1, and 212, Version 8.1 dated September 1, 2017, 8.74×10^{-8} ton of diesel particulate exhaust per year would generate a health risk of 0.0015 in one million, which is less than the significance threshold of an increased probability of 10 cancer cases in one million. The December 2015 Final PEA for NOx RECLAIM used an EMFAC 2011 emission factor of 1.67 grams per hour of diesel particulate matter for heavy-duty trucks and assumed idling at 15 minutes per trip. The updated emission factor and idling time results in a significant decrease in estimated vehicular emissions.

4.2.2.3 Individual Facility Analyses For Construction and Operation

The overall objective of the proposed project is to reduce NOx emissions. However, in consideration of the complexity involved with operating FCCUs, SRU/TGs, refinery boilers/heaters, coke calciners, and gas turbines, the equipment operators utilize a combination of

[6] CARB, Airborne Toxic Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling, September 2016. https://www.arb.ca.gov/msprog/truck-idling/13ccr2485_09022016.pdf

various emission control equipment and techniques to control not only NOx, but other pollutants such as SOx, CO, PM10, PM2.5, and ammonia slip, as applicable, while maintaining overall efficiency. As there is no way to fully predict on a case-by-case basis what each facility operator will do to comply with the proposed project, the estimates in this SEA are based on estimates provided in the Draft Staff Report (which are based on information reported by the refineries in the survey and information from the air pollution control device manufacturers as well as the consultant reports prepared for each affected facility) combined with the assumptions applied in the previous CEQA documents such as the December 2015 Final PEA for NOx RECLAIM. In addition, South Coast AQMD staff met individually with each affected facility to obtain facility-specific information that helped refine the assumptions. Further, if a particular technology was identified as having a cost that exceeds $50,000 per ton, the analysis in this SEA assumes that the facility operator would not install this type of air pollution control technology in response to the proposed project. The 16 refinery facilities which would affected by PR 1109.1 have been anonymized and assigned facility identification codes 1 through 16.

Facility 1

Facility 1 operates the following combustion equipment which will be subject to PR 1109.1: 30 heaters, two SRU/TGs, one FCCU, and four gas turbines with duct burners. Tables 4.2-21 and 4.2-22 summarize the existing NOx air pollution control equipment and possible methods for achieving NOx emission reductions.

Table 4.2-21
Facility 1: Existing NOx Controls

Total Number of Equipment per Category	Equipment with LNBs	Equipment with ULNBs	Equipment with SCR	Equipment with SCR + LNBs	Equipment without NOx control
30 Heaters	~~19~~ 24	~~4~~ 2	~~2~~ 0	~~2~~ 4	~~3~~ 0
2 SRU/TGs	2	-	-	-	-
1 FCCU	-	-	1	-	-
4 Gas Turbines with Duct Burners	-	-	4	-	-

Table 4.2-22
Facility 1: Potential Methods to Achieve NOx BARCT

Total Number of Equipment per Category	ULNBs	New SCR	SCR Upgrade	New SCR + ULNBs	SCR Upgrade + ULNBs	No Changes Proposed
30 Heaters	-	~~5~~ 7	1	8	1	~~15~~ 13
2 SRU/TGs	1	-	-	-	-	1
1 FCCU	-	-	-	-	-	1
4 Gas Turbines with Duct Burners	-	-	-	-	-	4

In addition to installing new SCRs with associated ammonia storage tanks for two heaters, representatives from Facility 1 have indicated that they are planning to replace the two heaters.

For Facility 1, the December 2015 Final PEA for NOx RECLAIM previously analyzed construction and operational impacts associated with installing: 1) 14 new SCRs with 14 new aqueous ammonia storage tanks for 14 heaters; and 2) one LoTOx™ WGSs for one SRU/TG. Construction and operational impacts associated with ~~3)~~ upgrading one existing SCR for one gas turbine with a duct burner at Facility 1 were also previously analyzed in the December 2015 Final PEA for NOx RECLAIM. After the NOx RECLAIM program was amended in 2015, operators at Facility 1 installed ~~four~~ one new SCR~~s with associated aqueous ammonia storage tanks~~ for ~~four~~ one heater~~s~~. The potential air quality impacts associated with physical modifications that may occur at Facility 1 in order to achieve the BARCT limits in PR 1109.1 were partially addressed in the December 2015 Final PEA for NOx RECLAIM.

To achieve the BARCT limits at Facility 1 for the heater category per PR 1109.1, 13 new SCRs with 13 new aqueous ammonia storage tanks could be constructed for 13 heaters. However, 14 new SCRs and 14 new ammonia storage tanks for 14 heaters were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. After the NOx RECLAIM program was amended in 2015, ~~four~~ one SCR~~s with associated aqueous ammonia storage were~~ was installed. While the latest information provided by representatives of Facility 1 indicates plans to install one new SCR for two heaters, PR 1109.1 does not contain any requirements that would trigger a modification to reduce NOx emissions from these two heaters. Nonetheless, the analysis has been updated to reflect this additional SCR installation. Thus, the net change in the heater analysis between the December 2015 Final PEA for NOx RECLAIM and the proposed project is that ~~three~~ two additional new SCRs with ~~three~~ two new aqueous ammonia tanks would be installed [13 –(14 – ~~4~~ 1) + 2 = ~~3~~ 2 new SCRs].

While an upgrade~~s~~ to two of the four recently installed SCRs at Facility 1 could occur, construction impacts associated with an SCR upgrade would be minimal, or may not be needed at all, since the equipment is currently designed to achieve a NOx concentration of five ppm. Thus, no additional analysis of these upgrades to existing SCR for Facility 1 is needed in this SEA.

The analysis of the proposed project indicates that burners for one SRU/TG could be replaced with ULNBs. However, the December 2015 Final PEA for NOx RECLAIM analyzed an installation of a scrubber for the SRU/TG, which has greater estimated emission impacts greater than replacing burners with ULNBs.

The combustion equipment that was not previously analyzed in the December 2015 Final PEA for NOx RECLAIM for Facility 1 must be evaluated for impacts: 1) burners in nine heaters will be replaced with ULNBs, ~~and~~ 2) ~~three~~ two new SCR units with ~~three~~ two new aqueous ammonia storage tanks will be installed for ~~three~~ two heaters, and 3) two heaters will be replaced. This SEA updates the previous analysis in the December 2015 Final PEA for NOx RECLAIM to take into account the additional environmental impacts associated with implementing these additional activities at Facility 1.

During the rule development process, representatives from Facility 1 provided tailored emissions calculations based on their assessment of the type of construction equipment that would be needed and the timetable to implement construction of PR 1109.1-related projects such as the installation of a new SCR and the replacement of two heaters. Table 4.2-23 presents a summary of Facility 1's customized analysis.

Table 4.2-23
Estimated Construction Emissions ~~for One New SCR for One Heater/Boiler~~ (with ~~PM10/PM2.5 Mitigated~~Mitigation) as Provided by Representatives of Facility 1

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
New SCR (including Ammonia Storage Tank)	~~3.35~~ 2.13	~~37.42~~ 26.54	~~25.79~~ 27.79	~~0.09~~ 0.08	~~8.23~~ 7.83	~~2.66~~ 2.26
Heater Replacement	2.09	23.65	36.91	0.08	6.38	1.43

~~As with the analysis in the December 2015 Final PEA for NOx RECLAIM, the analysis in this SEA differentiates between construction impacts associated with installing an SCR for a boiler, heater, or gas turbine, versus an FCCU or a larger unit because less construction equipment and shorter construction duration are assumed to occur when installing an SCR for a boiler, heater, or gas turbine. The construction emission estimates provided by representatives of Facility 1 for the installation of a new SCR with an ammonia storage tank are similar to the unmitigated and mitigated construction emission estimates in Tables 4.2-12 and 4.2-13, respectively, for installing one new SCR for one FCCU. The mitigated construction emissions presented in Table 4.2-24 incorporates mitigation for PM10 and PM2.5 emissions to minimize fugitive dust in accordance with South Coast AQMD Rule 403 but does not included mitigated emissions from utilizing Tier 4 Final engines for all construction equipment that is rated at 50 hp or higher. For this reason, the analysis in this SEA for heaters at Facility 1 relies on the mitigated construction emissions presented in Table 4.2-13.~~

Table 4.2-24 presents the mitigated peak daily construction emissions for Facility 1 if 1) the replacement of the burners in nine heaters with ULNBs, ~~and~~ 2) the installation of ~~three~~ two new SCR units with ~~three~~ two new ammonia storage tanks for ~~three~~ two heaters, and 3) the replacement of two heaters occur on the same day.

Table 4.2-24
Facility 1: Mitigated Peak Daily Construction Emissions for NOx Control of Heaters

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Heaters						
9 Burner Replacements with ULNBs	15.81	84.42	529.49	0.98	7.35	3.56
~~3~~ 2 New SCRs	~~12.33~~ 4.26	~~38.44~~ 53.07	~~153.01~~ 55.57	~~0.34~~ 0.15	~~17.95~~ 15.66	~~5.82~~ 4.52
2 Heater Replacements	4.18	47.31	73.82	0.15	12.77	2.86
TOTAL	**~~28.14~~ 24.25**	**~~122.87~~ 184.80**	**~~682.49~~ 658.88**	**~~1.31~~ 1.28**	**~~25.30~~ 35.78**	**~~9.38~~ 10.94**
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**YES**	**YES**	**NO**	**NO**	**NO**

With the updated compliance strategy, the peak daily construction emissions from Facility 1 would increase for NOx, PM10 and PM2.5 and would decrease for VOC, CO and SOx. However, these changes would not change any of the conclusions (e.g., NOx and CO will remain significant and VOC, SOx, PM10 and PM2.5 will remain less than significant). Thus, none of these revisions: 1) contain significant new information; 2) will result in significant new environmental impact not previously disclosed; and 3) there is no substantial increase in the severity of the previously identified impacts. Therefore, none of these revisions contain the type of significant new information that requires recirculation of the Draft SEA for further public comment under CEQA Guidelines Sections 15073.5 and 15088.5.

Operation activities associated with SCR technology are periodic ammonia deliveries, and the associated haul trips with delivering fresh catalyst and hauling away spent catalyst. The ~~three~~ two new SCRs will be required by South Coast AQMD policy to utilize 19% aqueous ammonia. By taking a ratio of the maximum heat input rate of the heaters requiring new SCR to the average maximum heat input rate of the heaters analyzed for this facility in the December 2015 Final PEA for NOx RECLAIM, an additional ~~30,846~~ 20,564 gallons per year of 19% aqueous ammonia is estimated to be needed to operate the ~~three~~ two new SCRs. The additional ammonia is expected to be delivered to the facility via ~~five~~ three 7,000-gallon trucks per year, but no more than one 100-mile round-trip ammonia truck delivery per day. One 25-ton capacity truck will be required to haul spent catalyst 260 round trip miles once every five years, and one 25-ton capacity truck will be required to deliver fresh catalyst 100 miles round-trip once every five years; however, it is assumed that only one of these trucks would operate on a given day and the greater distance is 260 round trip miles. The peak day operational emissions for Facility 1 are presented in Table 4.2-25.

Table 4.2-25
Facility 1: Operational Emissions

Peak Daily Operational Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
1 T7 Diesel Truck for Ammonia Delivery (100 miles round-trip) + 1 T7 Diesel Truck for Catalyst Delivery/Hauling (260 miles round-trip)	0.08	3.02	0.34	0.01	0.04	0.04
South Coast AQMD Air Quality Significance Threshold for Operation	55	55	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

T7 is the EMFAC vehicle category designation for heavy-heavy duty trucks.

Facility 2

Facility 2 operates one petroleum coke calciner which does not currently have any NOx emission control equipment. For the proposed project, there are three types of air pollution control devices that may be installed in order to reduce NOx emissions: one new SCR with a new ammonia tank, LoTOx™ with WGS, or UltraCat™ with DGS.

The December 2015 Final PEA for NOx RECLAIM previously analyzed the possible installations of LoTOx™ with WGS, and UltraCat™ with DGS for the petroleum coke calciner at Facility 2. Worst-case construction and operation impacts for both types of scrubbers as analyzed in the December 2015 Final PEA for NOx RECLAIM are summarized in Tables 4.2-26 and 4.2-27, respectively.

Table 4.2-26
Facility 2: Mitigated Peak Daily Construction Emissions for Installing Either LoTOx™ with WGS or UltraCat™ with DGS

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
December 2015 Final PEA for NOx RECLAIM: Install LoTOx™ with WGS or UltraCat™ with DGS	36	104	233	0.20	30	12
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**YES**	**NO**	**NO**	**NO**	**NO**

Source: See Table 4.2-12, Refinery Facility 2, of the December 2015 Final PEA for NOx RECLAIM.

Table 4.2-27
Facility 2: Peak Daily Emissions for Operating Either LoTOx™ with WGS or UltraCat™ with DGS

Peak Daily Operation Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
December 2015 Final PEA for NOx RECLAIM: Operate LoTOx™ with WGS or UltraCat™ with DGS	0.89	10.42	4.01	0.02	0.52	0.43
South Coast AQMD Air Quality Significance Threshold for Operation	55	55	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

Source: See Appendix E, Facility 2, of the December 2015 Final PEA for NOx RECLAIM.

The operational analysis in the December 2015 Final PEA for NOx RECLAIM concluded that the UltraCat™ DGS would utilize ammonia and require more electricity to operate, while LoTOx™ with WGS would utilize sodium hydroxide and water, require more plot space, and result in more water and solid waste generation. After the NOx RECLAIM Program was amended in 2015, operators of Facility 2 did not install any air pollution control equipment.

While the environmental impacts associated with the application of SCR technology specifically for the petroleum coke calciner were not previously analyzed in the December 2015 Final PEA for NOx RECLAIM, an SCR installation for FCCUs was previously analyzed. An SCR for the petroleum coke calciner would be similar in scale to what would be needed to install an SCR for a FCCU. When comparing the construction impacts associated with installing a new SCR for a FCCU, as previously presented in Table 4.2-13, to installing either of the two types of scrubbers as were previously analyzed in the December 2015 Final PEA for NOx RECLAIM, the environmental impacts from installing either of the two types of scrubbers continue to represent the worst-case. Thus, construction and operation activities that operators of Facility 2 may employ in order to reduce NOx emissions from the petroleum coke calciner for the proposed project were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Further, no additional or different construction and operation impacts than what was previously analyzed in the December 2015 Final PEA for NOx RECLAIM, would be required as a result of implementing PR 1109.1. Thus, no additional analysis in this SEA is needed.

Facility 3

Facility 3 operates the following combustion equipment which will be subject to PR 1109.1: two boilers and two SRU/TGs. Tables 4.2-28 and 4.2-29 summarize the existing NOx air pollution control equipment and possible methods for achieving NOx emission reductions.

Table 4.2-28
Facility 3: Existing NOx Controls

Total Number of Equipment Per Category	Equipment with LNBs	Equipment with ULNBs	Equipment with SCR	Equipment with SCR + LNBs	Equipment without NOx Control
2 Boilers	~~-~~2	-	-	-	~~2~~0
2 SRU/TGs	~~1~~0	-	-	-	~~1~~2

Table 4.2-29
Facility 3: Potential Methods to Achieve NOx BARCT

Total Number of Equipment per Category	ULNB	New SCR	SCR Upgrade	New SCR + ULNBs	SCR Upgrade + ULNBs	No Changes Proposed
2 Boilers	-	~~-~~2	-	~~1~~0	-	~~1~~0
2 SRU/TGs	2	-	-	-	-	-

For Facility 3, the December 2015 Final PEA for NOx RECLAIM previously analyzed construction and operational impacts associated with installing two new SCRs with two aqueous ammonia storage tanks for two boilers. After the NOx RECLAIM program was amended in 2015, operators of Facility 3 did not install any air pollution control equipment. The potential air quality impacts associated with physical modifications that may occur at Facility 3 in order to achieve the BARCT limits in PR 1109.1 for boilers were previously analyzed in the December 2015 Final PEA for NOx RECLAIM.

~~Under the proposed project, only one boiler is expected to need a new SCR but it will also be expected to undergo burner replacement with ULNBs. Due to the new SCR for this one boiler having been previously analyzed in the December 2015 Final PEA for NOx RECLAIM, the analysis for this boiler in this SEA only needs to include the environmental impacts associated with replacing the existing burners with ULNBs.~~

In addition, the proposed project may result in Facility 3 replacing burners in two SRU/TGs with ULNBs.

~~The potential air quality impacts associated with physical modifications that may occur during construction at Facility 3 in order to achieve the BARCT limits in PR 1109.1 were partially addressed in the December 2015 Final PEA for NOx RECLAIM for the boiler.~~ This SEA updates the previous analysis in the December 2015 Final PEA for NOx RECLAIM to include the replacement of burners with ULNBs for ~~one boiler and~~ two SRU/TGs at Facility 3. Table 4.2-30 presents the peak daily construction emissions for concurrently replacing the burners on ~~one boiler and~~ two SRU/TGs with ULNBs at Facility 3.

Table 4.2-30
Facility 3: Mitigated Peak Daily Construction Emissions for NOx Control of One Boiler and Two SRU/TGs

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
~~*Boiler*~~						
~~1 Burner Replacement with ULNBs~~	~~1.76~~	~~9.38~~	~~58.83~~	~~0.11~~	~~0.82~~	~~0.40~~
SRU/TGs						
2 Burner Replacements with ULNBs	3.51	18.76	117.66	0.22	1.63	0.79
TOTAL	**~~5.27~~ 3.51**	**~~28.14~~ 18.76**	**~~176.50~~ 117.66**	**~~0.33~~ 0.22**	**~~2.45~~ 1.63**	**~~1.19~~ 0.79**
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

~~Since the new SCR for the boiler was previously analyzed in the December 2015 Final PEA for NOx RECLAIM, the operational impacts associated with deliveries with ammonia were also previously analyzed in the December 2015 Final PEA for NOx RECLAIM and are not repeated in this SEA. Moreover, o~~Once the ULNBs are installed for ~~the boiler and~~ the SRU/TGs, since ULNBs do not utilize chemicals or catalyst for their operation, no additional adverse operational impacts for Facility 3, beyond what was previously analyzed in the December 2015 Final PEA for NOx RECLAIM, are expected to occur.

Facility 4

Facility 4 operates the following combustion equipment which will be subject to PR 1109.1: ~~31~~ 28 heaters and boilers, and two gas turbines. Tables 4.2-31 and 4.2-32 summarize the existing NOx air pollution control equipment and possible methods for achieving NOx emission reductions.

Table 4.2-31
Facility 4: Existing NOx Controls

Total Number of Equipment per Category	Equipment with LNBs	Equipment with ULNBs	Equipment with SCR	Equipment with SCR + LNBs	Equipment without NOx Control
~~31~~ 28 Heaters/Boilers	~~9~~6	-	~~2~~3	13	~~7~~6
2 Gas Turbines	-	-	2	-	-

Table 4.2-32
Facility 4: Potential Methods to Achieve NOx BARCT

Total Number of Equipment per Category	ULNBs	New SCR	SCR Upgrade	New SCR + ULNBs	SCR Upgrade + ULNBs	No Changes Proposed
~~31~~28 Heaters/Boilers	~~1~~0	~~-~~16	~~3~~0	~~12~~2	-	~~15~~10
2 Gas Turbines	-	-	2	-	-	-

In addition to installing new SCRs with associated ammonia storage tanks for seven heaters/boilers, representatives from Facility 4 have indicated that they are planning to replace the seven heaters/boilers.

For Facility 4, the December 2015 Final PEA for NOx RECLAIM previously analyzed construction and operational impacts associated with installing: 1) six new SCRs with six aqueous ammonia storage tanks for six heaters/boilers; and 2) one LoTOx™ with WGS for one FCCU. Also, construction and operational impacts associated with 3) upgrading one existing SCR for one gas turbine with duct burner at Facility 4 was previously analyzed in December 2015 Final PEA for NOx RECLAIM. After the NOx RECLAIM Program was amended in 2015, operators of Facility 4 did not install any air pollution control equipment but the FCCU and three associated heaters were~~was~~ shut down.

The seven heaters/boilers mentioned above, in addition to another three heaters/boilers which will have other control and one heater/boiler which was shut down, will not require replacement with ULNB; thus the updated analysis will evaluate two burner replacements with ULNBs [13 – 7 – 3 – 1 = 2 burner replacements with ULNBs].

~~To achieve the BARCT limits at Facility 4 for the heater/boiler category per PR 1109.1, 12 heaters/boilers are expected to need a new SCR and burner replacements with ULNBs at Facility 4. In addition, the proposed project may result in Facility 4 replacing the burners in one heater/boiler.~~ Upgrades of existing SCRs for ~~three heaters/boilers and~~ two gas turbines are also expected.

The potential air quality impacts associated with physical modifications that may occur at Facility 4 in order to achieve the BARCT limits in PR 1109.1 were partially addressed in the December 2015 Final PEA for NOx RECLAIM for the six heaters/boilers.

To achieve the BARCT limits at Facility 4 for the heater/boiler category per PR 1109.1, 12 new SCRs with 12 new aqueous ammonia storage tanks could be constructed for 12 heaters/boilers. While the latest information provided by representatives of Facility 4 indicates plans to install five new SCRs for five heaters/boilers, PR 1109.1 does not contain any requirements that would trigger a modification to reduce NOx emissions from these five heaters/boilers. Nonetheless, the analysis has been updated to reflect these additional SCR installations. Also, representatives of Facility 4 indicated plans to install three new SCRs for three heaters/boilers which were previously analyzed for SCR upgrade. Of the three associated heaters which were shut down, two were previously analyzed in the Draft SEA for new SCR installation. However, six new SCRs and six new ammonia storage tanks for six heaters/boilers were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. After the NOx RECLAIM program was amended in 2015, no new SCRs with associated aqueous ammonia storage were installed. Thus, the net change in the heaters/boilers analysis between the December 2015 Final PEA for NOx RECLAIM and the proposed project is that ~~six~~ 12 additional new SCRs with ~~six~~ 12 new aqueous ammonia tanks would be installed [12 + 5 + 3 – 2 –(6 – 0) = ~~6~~ 12 new SCRs]. Because the proposed rules do not require the installation of all SCR on one day, for practical purposes, it is assumed that a maximum of six SCR would undergo construction concurrently.

Facility 4 has two existing SCRs that could be upgraded for two gas turbines. However, one SCR upgrade for a gas turbine was previously analyzed in the December 2015 Final PEA for NOx RECLAIM. After the NOx RECLAIM program was amended in 2015, no existing SCRs were upgraded. Thus, the net change in the SCR upgrade analysis for gas turbines between the December 2015 Final PEA for NOx RECLAIM and the proposed project is that one additional upgrade of an existing SCR would occur [2 –(1 – 0) = 1 additional SCR upgrade].

The combustion equipment that was not previously analyzed in the December 2015 Final PEA for NOx RECLAIM for Facility 4 must be evaluated for impacts: 1) ~~13~~ two heaters/boilers will have their burners replaced with ULNBs; 2) six new SCR units with six new aqueous ammonia storage tanks will be installed for six heaters/boilers; 3) ~~three existing SCRs for three heaters/boilers will be upgraded; and 4)~~ one existing SCR for one gas turbine will be upgraded; and 4) seven heaters/boilers will be replaced. This SEA updates the previous analysis in the December 2015 Final PEA for NOx RECLAIM to take into account the additional environmental impacts associated with implementing these additional activities at Facility 4.

During the rule development process, representatives from Facility 4 provided tailored emissions calculations based on their assessment of the type of construction equipment that would be needed and the timetable to implement construction of PR 1109.1-related projects such as the installation of a new SCR and the replacement of heaters/boilers. Table 4.2-33 presents a summary of Facility 4's customized analysis.

Table 4.2-33
Estimated Construction Emissions ~~for One New SCR for One Heater/Boiler~~ (with ~~PM10/PM2.5 Mitigated~~Mitigation) as Provided by Representatives of Facility 4

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
New SCR (including Ammonia Storage Tank)	~~3.35~~ 2.13	~~37.42~~ 26.54	~~25.79~~ 27.79	~~0.09~~ 0.08	~~8.23~~ 7.83	~~2.66~~ 2.26
Heater/Boiler Replacement	2.09	23.65	36.91	0.08	6.38	1.43

~~As with the analysis in the December 2015 Final PEA for NOx RECLAIM, the analysis in this SEA differentiates between construction impacts associated with installing an SCR for a boiler, heater, or gas turbine, versus an FCCU or a larger unit because less construction equipment and shorter construction duration are assumed to occur when installing an SCR for a boiler, heater, or gas turbine. The construction emission estimates provided by representatives of Facility 4 for the installation of a new SCR with an ammonia storage tank are similar to the unmitigated and mitigated construction emission estimates in Tables 4.2-12 and 4.2-13, respectively, for installing one new SCR for one FCCU. The mitigated construction emissions presented in Table 4.2-34 incorporates mitigation for PM10 and PM2.5 emissions to minimize fugitive dust in accordance with South Coast AQMD Rule 403 but do not include mitigated emissions from utilizing Tier 4 Final engines for all construction equipment that is rated at 50 hp or higher. For this reason, the~~

~~analysis in this SEA for heaters/boilers at Facility 4 relies on the mitigated construction emissions presented in Table 4.2-13.~~

Table 4.2-34 presents the mitigated peak daily construction emissions for Facility 4 if the following activities concurrently occur: 1) replacement of the burners in ~~13~~ two heaters with ULNBs; 2) installation of six new SCR units with six new ammonia storage tanks for six heaters; 3) upgrade one existing SCR for one gas turbine; and 4) seven heaters/boilers will be replaced.

Table 4.2-34
Facility 4: Mitigated Peak Daily Construction Emissions for NOx Control

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Heaters/Boilers						
~~13~~ 2 Burner Replacements with ULNBs	~~22.84~~ 3.51	~~121.94~~ 18.76	~~764.81~~ 117.66	~~1.41~~ 0.22	~~10.62~~ 1.63	~~5.15~~ 0.79
6 New SCRs	~~24.65~~ 12.77	~~76.89~~ 159.21	~~306.02~~ 166.72	~~0.67~~ 0.46	~~35.90~~ 46.97	~~11.63~~ 13.57
~~3 SCR Upgrades~~	~~0.86~~	~~8.36~~	~~24.85~~	~~0.05~~	~~1.22~~	~~0.35~~
7 Heater/Boiler Replacements	14.63	165.58	258.37	0.54	44.68	10.00
Gas Turbine						
1 SCR Upgrade	0.29	2.79	8.28	0.02	0.41	0.12
TOTAL	~~**48.64**~~ **31.20**	~~**209.99**~~ **346.34**	~~**1103.97**~~ **551.04**	~~**2.16**~~ **1.24**	~~**48.14**~~ **93.69**	~~**17.24**~~ **24.48**
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**YES**	**YES**	**NO**	**NO**	**NO**

With the updated compliance strategy, the peak daily construction emissions from Facility 1 would increase for NOx, PM10 and PM2.5 and would decrease for VOC, CO and SOx. However, these changes would not change any of the conclusions (e.g., NOx and CO will remain significant and VOC, SOx, PM10 and PM2.5 will remain less than significant). Thus, none of these revisions: 1) contain significant new information; 2) will result in significant new environmental impact not previously disclosed; and 3) there is no substantial increase in the severity of the previously identified impacts. Therefore, none of these revisions contain the type of significant new information that requires recirculation of the Draft SEA for further public comment under CEQA Guidelines Sections 15073.5 and 15088.5.

Operation activities associated with SCR technology are periodic ammonia deliveries, and the associated haul trips with delivering fresh catalyst and hauling away spent catalyst. The ~~six~~ 12 new SCRs will be required by South Coast AQMD policy to utilize 19% aqueous ammonia. The ~~four~~ existing SCRs currently utilize anhydrous ammonia, and will be expected to continue to use anhydrous ammonia after the upgrades are completed; no additional ammonia, electricity, or vehicle trips will be needed for these units. By taking a ratio of the maximum heat input rate of the heaters/boilers requiring new SCR to the average maximum heat input rate of the heaters/boilers analyzed for this facility in the December 2015 Final PEA for NOx RECLAIM, an additional ~~64,133~~128,265 gallons per year of 19% aqueous ammonia is estimated to be needed to operate the

~~six~~ 12 new SCRs. The additional ammonia is expected to be delivered to the facility via ~~10~~ 19 7,000-gallon trucks per year, but no more than one round-trip at 100 miles per trip per day. ~~One~~ Two 25-ton capacity truck will be required to haul spent catalyst 260 round trip miles once every five years, and ~~one~~ two 25-ton capacity truck will be required to deliver fresh catalyst 100 miles round-trip once every five years; however, it is assumed that only one of these trucks would operate on a given day and the greater distance is 260 round trip miles. The peak daily operational emissions for Facility 4 are presented in Table 4.2-35.

Table 4.2-35
Facility 4: Operational Emissions

Peak Daily Operational Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
1 T7 Diesel Truck for Ammonia Delivery (100 miles round-trip) + 1 T7 Diesel Truck for Catalyst Delivery/Hauling (260 miles round-trip)	0.08	3.02	0.34	0.01	0.04	0.04
South Coast AQMD Air Quality Significance Threshold for Operation	55	55	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

T7 is the EMFAC vehicle category designation for heavy-heavy duty trucks.

Facility 5

Facility 5 operates the following combustion equipment which will be subject to PR 1109.1: 34 heaters/boilers, seven SRU/TGs, one FCCU, five thermal oxidizers, and four gas turbines with duct burners. Tables 4.2-36 and 4.2-37 summarize the existing NOx air pollution control equipment and possible methods for achieving NOx emission reductions.

Table 4.2-36
Facility 5: Existing NOx Controls

Total Number of Equipment per Category	Equipment with LNBs	Equipment with ULNBs	Equipment with SCR	Equipment with SCR + LNBs	Equipment without NOx Control
34 Heaters/Boilers	10	-	4	11	9
7 SRU/TGs	3	1	-	-	3
1 FCCU	-	-	1	-	-
5 Thermal Oxidizers	1	-	-	-	4
4 Gas Turbines with Duct Burners	-	-	4	-	-

Table 4.2-37
Facility 5: Potential Methods to Achieve NOx BARCT

Total Number of Equipment per Category	ULNBs	New SCR	SCR Upgrade	New SCR + ULNBs	SCR Upgrade + ULNBs	No Changes Proposed
34 Heaters/Boilers	1	2	1	10	-	20
7 SRU/TGs	3	-	-	-	-	4
1 FCCU	-	-	-	-	-	1
5 Thermal Oxidizers	2	-	-	-	-	3
4 Gas Turbines with Duct Burners	-	-	3	-	-	1

For Facility 5, the December 2015 Final PEA for NOx RECLAIM previously analyzed construction and operational impacts associated with installing: 1) nine new SCRs with nine aqueous ammonia storage tanks for nine heaters/boilers; 2) one new SCR with an aqueous ammonia storage tank for one FCCU and one SRU/TG with a combined stack; and 3) two LoTOx™ with WGS for two SRU/TGs. Also, construction and operational impacts associated with 4) upgrading three SCRs for three gas turbines with duct burners were previously analyzed for Facility 5 in the December 2015 Final PEA for NOx RECLAIM. After the NOx RECLAIM Program was amended in 2015, operators of Facility 5 installed one SCR with an associated aqueous ammonia storage tank for the FCCU and SRU/TG combined stack. The potential air quality impacts associated with physical modifications that may occur at Facility 5 in order to achieve the BARCT limits in PR 1109.1 were partially addressed in the December 2015 Final PEA for NOx RECLAIM.

To achieve the BARCT limits at Facility 5 for the heater/boiler category per PR 1109.1, 12 new SCRs with associated aqueous ammonia storage tanks could be constructed for 12 heater/boilers. However, nine new SCRs with and nine ammonia storage tanks for nine heaters/boilers were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. After the NOx RECLAIM program was amended in 2015, no new SCRs with associated aqueous ammonia storage tanks were previously installed for heaters/boilers at Facility 5. Thus, the net change in the heaters/boilers analysis between the December 2015 Final PEA for NOx RECLAIM and the proposed project is that three additional new SCRs with three new aqueous ammonia tanks would be installed [12 –(9 – 0) = 3 new SCRs].

The burners for three SRU/TGs could be replaced with ULNBs. The December 2015 Final PEA for NOx RECLAIM previously analyzed the installation of two LoTOx™ with WGS for two SRU/TGs, which resulted in more emissions than what would occur if the burners in the two SRU/TGs were replaced with ULNBs. Thus, the net change in the burner replacement analysis for SRU/TGs between the December 2015 Final PEA for NOx RECLAIM and the proposed project is that one SRU/TG would have its burners replaced with ULNBs [(3 – 2) = 1 burner replacement].

The existing SCRs for the three gas turbines at Facility 5 could also be upgraded. However, SCR upgrades for all three gas turbines were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. After the NOx RECLAIM program was amended in 2015, no existing SCRs for the gas turbines were upgraded. Thus, the net change in the SCR upgrade analysis for gas turbines between the December 2015 Final PEA for NOx RECLAIM and the proposed project is that no additional SCR upgrades need to be analyzed in this SEA [3- (3 – 0) = 0 SCR upgrades for gas turbines].

The combustion equipment that was not previously analyzed in the December 2015 Final PEA for NOx RECLAIM for Facility 5 must be evaluated for impacts: 1) burners in 11 heaters/boilers will be replaced with ULNBs; 2) three new SCR units with three new aqueous ammonia storage tanks will be installed for three heaters/boilers; 3) one existing SCR for one heater/boiler will be upgraded; 4) burners in one SRU/TG will be replaced with ULNBs; and 5) burners in two thermal oxidizers will be replaced with ULNBs. This SEA updates the previous analysis in the December 2015 Final PEA for NOx RECLAIM to take into account the additional environmental impacts associated with implementing these additional activities at Facility 5.

Table 4.2-38 presents the mitigated peak daily construction emissions for Facility 5 if all of the aforementioned equipment installation and upgrade activities concurrently occur.

Table 4.2-38
Facility 5: Mitigated Peak Daily Construction Emissions for NOx Control

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Heaters/Boilers						
11 Burner Replacements with ULNBs	19.32	103.18	647.15	1.19	8.98	4.36
3 New SCRs	3.47	17.15	51.37	0.10	3.40	1.32
1 SCR Upgrade	0.29	2.79	8.28	0.02	0.41	0.12
SRU/TGs						
1 Burner Replacement with ULNBs	1.76	9.38	58.83	0.11	0.82	0.40
Thermal Oxidizers						
2 Burner Replacements with ULNBs	3.51	18.76	117.66	0.22	1.63	0.79
TOTAL	**28.35**	**151.26**	**883.30**	**1.64**	**15.24**	**6.98**
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**YES**	**YES**	**NO**	**NO**	**NO**

Facility 5 currently manufactures its own supply of ammonia and the facility's representatives indicated that the quantity of ammonia manufactured should be able to accommodate any additional ammonia needed for the three new SCRs. For this reason, no additional vehicle trips to deliver ammonia to the facility will be necessary. One 25-ton capacity truck will be required to haul spent catalyst 260 round trip miles once every five years, and one 25-ton capacity truck will be required to deliver fresh catalyst 100 miles round-trip once every five years; however, it is assumed that only one of these trucks would operate on a given day and the greater distance is 260 round trip miles. The peak daily operational emissions for Facility 5 are presented in Table 4.2-39:

Table 4.2-39
Facility 5: Operational Emissions

Peak Daily Operational Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
1 T7 Diesel Truck for Catalyst Delivery/Hauling (260 miles round-trip)	0.06	2.18	0.25	0.01	0.03	0.03
South Coast AQMD Air Quality Significance Threshold for Operation	55	550	55	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

T7 is the EMFAC vehicle category designation for heavy-heavy duty trucks.

Facility 6

Facility 6 operates the following combustion equipment which will be subject to PR 1109.1: 28 heaters/boilers, two SRU/TGs, one FCCU, two thermal oxidizers, and one gas turbine. Tables 4.2-40 and 4.2-41 summarize the existing NOx air pollution control equipment and possible methods for achieving NOx emission reductions.

Table 4.2-40
Facility 6: Existing NOx Controls

Total Number of Equipment per Category	Equipment with LNBs	Equipment with ULNBs	Equipment with SCR	Equipment with SCR + LNBs	Equipment without NOx Control
28 Heaters/Boilers	17	-	2	6	3
2 SRU/TGs	-	-	-	-	2
1 FCCU	-	-	1	-	-
2 Thermal Oxidizers	-	-	-	-	2
1 Gas Turbine	-	-	-	1	-

Table 4.2-41
Facility 6: Potential Methods to Achieve NOx BARCT

Total Number of Equipment per Category	ULNBs	New SCR	SCR Upgrade	New SCR + ULNBs	SCR Upgrade + ULNBs	No Changes Proposed
28 Heaters/Boilers	-	2	1	10	-	15
2 SRU/TGs	1	-	-	-	-	1
1 FCCU	-	-	-	-	-	1
2 Thermal Oxidizers	1	-	-	-	-	1
1 Gas Turbine	-	-	-	-	-	1

For Facility 6, the December 2015 Final PEA for NOx RECLAIM previously analyzed construction and operational impacts associated with installing: 1) 15 new SCRs with 15 new aqueous ammonia storage tanks for 15 heaters/boilers; 2) one LoTOx™ with WGS for one SRU/TG;

and 3) one new SCR with one new aqueous ammonia storage tank for one FCCU. In addition, construction and operational impacts associated with 4) upgrading one existing SCR for one gas turbine with duct burner at Facility 6 were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. After the NOx RECLAIM program was amended in 2015, operators of Facility 6 installed four new SCRs with associated aqueous ammonia storage tanks for four heaters/boilers, and one new SCR with an associated aqueous ammonia storage tank for the FCCU. The potential air quality impacts associated with physical modifications that may occur at Facility 6 in order to achieve the BARCT limits in PR 1109.1 were partially addressed in the December 2015 Final PEA for NOx RECLAIM.

To achieve the BARCT limits at Facility 6 for the heater/boiler category per PR 1109.1, 12 new SCRs with associated aqueous ammonia storage tanks could be constructed for 12 heaters/boilers. However, 15 new SCRs and 15 new ammonia storage tanks for 15 heaters/boilers were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. After the NOx RECLAIM program was amended in 2015, four new SCRs with associated aqueous ammonia storage tanks were installed at Facility 6. In order to estimate the potential environmental impacts for the additional equipment that did not have identical maximum heat ratings to equipment previously analyzed in the December 2015 Final PEA for NOx RECLAIM, this SEA relied on estimates from equipment with similar maximum heat input ratings as a surrogate. There is no similarly rated surrogate for one heater/boiler analyzed in the December 2015 Final PEA for NOx RECLAIM for new SCR. Thus, the net change in the heaters/boilers analysis between the December 2015 Final PEA for NOx RECLAIM and the proposed project is that two additional new SCRs with two new aqueous ammonia tanks would be installed [12 –(15 – 4 – 1) = 2 new SCRs for heaters/boilers].

While an upgrade to one of the four recently installed SCRs at Facility 6 could occur, construction impacts associated with an SCR upgrade would be minimal, or may not be needed at all, since the equipment is currently designed to achieve a NOx concentration of five ppm. Thus, no additional analysis of an upgrade to an existing SCR for Facility 6 is needed in this SEA.

The burners for one SRU/TG could be replaced with ULNBs. The December 2015 Final PEA for NOx RECLAIM previously analyzed the installation of one LoTOx™ with WGS for the SRU/TG, which had greater emissions impacts than what would occur to replace the burners with ULNBs. Thus, this SEA would require no additional analysis for the SRU/TG.

The combustion equipment that was not previously analyzed in the December 2015 Final PEA for NOx RECLAIM for Facility 6 must be evaluated for impacts: 1) burners in 10 heaters/boilers will be replaced with ULNBs, 2) two new SCR units with two new aqueous ammonia storage tanks will be installed for two heaters/boilers, and 3) burners in one thermal oxidizer will be replaced with ULNBs. This SEA updates the previous analysis in the December 2015 Final PEA for NOx RECLAIM to take into account the additional environmental impacts associated with implementing these additional activities at Facility 6.

Table 4.2-42 presents the mitigated peak daily construction emissions for Facility 6 if all of the aforementioned equipment installation and upgrade activities not analyzed in the December 2015 Final PEA concurrently occur.

Table 4.2-42
Facility 6: Mitigated Peak Daily Construction Emissions for NOx Control

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Heaters/Boilers						
10 Burner Replacements with ULNBs	17.57	93.80	588.32	1.09	8.17	3.96
2 New SCRs	2.31	11.43	34.25	0.07	2.27	0.88
Thermal Oxidizer						
1 Burner Replacement with ULNBs	1.76	9.38	58.83	0.11	0.82	0.40
TOTAL	**21.64**	**114.61**	**681.40**	**1.26**	**11.25**	**5.24**
South Coast AQMD Air Quality Significance Threshold for Construction	75	**100**	**550**	150	150	55
Exceed Significance?	**NO**	**YES**	**YES**	**NO**	**NO**	**NO**

Operation activities associated with SCR technology are periodic ammonia deliveries, and the associated haul trips with delivering fresh catalyst and hauling away spent catalyst. The two new SCRs will be required by South Coast AQMD policy to utilize 19% aqueous ammonia. By taking a ratio of the maximum heat input rate of the heaters/boilers requiring new SCRs to the average maximum heat input rate of the heaters/boilers analyzed for the facility in the December 2015 Final PEA for NOx RECLAIM, an additional 128,534 gallons of 19% aqueous ammonia is estimated to be needed to operate the new SCRs. The additional ammonia is expected to be delivered to the facility via 19 7,000-gallon trucks per year, but no more than one round trip at 100 miles per day. One 25-ton capacity truck will be required to haul spent catalyst 260 round trip miles once every five years, and one 25-ton capacity truck will be required to deliver fresh catalyst 100 miles round-trip once every five years; however, it is assumed that only one of these trucks would operate on a given day and the greater distance is 260 round trip miles. The peak daily operational emissions for Facility 6 are as follows in Table 4.2-43.

Table 4.2-43
Facility 6: Operational Emissions

Peak Daily Operational Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
1 T7 Diesel Truck for Ammonia Delivery (100 miles round-trip) + 1 T7 Diesel Truck for Catalyst Delivery/Hauling (260 miles round-trip)	0.08	3.02	0.34	0.01	0.04	0.04
South Coast AQMD Air Quality Significance Threshold for Operation	55	55	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

T7 is the EMFAC vehicle category designation for heavy-heavy duty trucks.

Facility 7

Facility 7 operates the following combustion equipment which will be subject to PR 1109.1: 34 heaters/boilers, two sulfuric acid plants, two SRU/TGs, one FCCU, and one gas turbine with duct burner. Tables 4.2-44 and 4.2-45 summarize the existing NOx air pollution control equipment and possible methods for achieving NOx emission reductions.

Table 4.2-44
Facility 7: Existing NOx Controls

Total Number of Equipment per Category	Equipment with LNBs	Equipment with ULNBs	Equipment with SCR	Equipment with SCR + LNBs	Equipment without NOx Control
34 Heaters/Boilers	28	-	1	3	2
2 Sulfuric Acid Plants	2	-	-	-	-
2 SRU/TGs	2	-	-	-	-
1 FCCU	-	-	-	-	1
1 Gas Turbine with Duct Burner	-	-	1	-	-

Table 4.2-45
Facility 7: Potential Methods to Achieve NOx BARCT

Total Number of Equipment per Category	ULNBs	New SCR	SCR Upgrade	New SCR + ULNBs	SCR Upgrade + ULNBs	No Changes Proposed
34 Heaters/Boilers	-	2	1	6	-	25
2 Sulfuric Acid Plants	-	-	-	-	-	2
2 SRU/TGs	-	-	-	-	-	2
1 FCCU	-	1	-	-	-	-
1 Gas Turbine with Duct Burner	-	-	-	-	-	1

For Facility 7, the December 2015 Final PEA for NOx RECLAIM previously analyzed construction and operational impacts associated with installing: 1) nine new SCRs with nine aqueous ammonia storage tanks for nine heaters/boilers; and 2) one wet gas scrubber for one FCCU. Construction and operational impacts associated with 3) upgrading one SCR for one gas turbine with duct burner at Facility 7 was also previously analyzed in the December 2015 Final PEA for NOx RECLAIM. After the NOx RECLAIM program was amended in 2015, operators of Facility 7 installed two SCRs with associated aqueous ammonia storage tanks for two heaters/boilers. The potential air quality impacts associated with physical modifications that may occur at Facility 7 in order to achieve the BARCT limits in PR 1109.1 were partially addressed in the December 2015 Final PEA for NOx RECLAIM.

To achieve the BARCT limits at Facility 7 for the heater/boiler category per PR 1109.1, eight new SCRs with eight new aqueous ammonia storage tanks could be constructed for eight heaters/boilers. However, nine new SCRs with associated ammonia storage tanks for nine heaters/boilers were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. After the NOx RECLAIM program was amended in 2015, two new SCRs with associated aqueous ammonia storage tanks were installed. In order to estimate the potential environmental impacts for the additional equipment that did not have identical maximum heat ratings to equipment previously analyzed in the December 2015 Final PEA for NOx RECLAIM, this SEA relied on estimates from equipment with similar maximum heat input ratings as a surrogate. There is no similarly rated surrogate for one heater/boiler analyzed in the December 2015 Final PEA for NOx RECLAIM for new SCR. Thus, the net change in the heaters/boilers analysis between the December 2015 Final PEA for NOx RECLAIM and the proposed project is that two additional new SCRs with two new aqueous ammonia tanks would be installed [8 –(9 – 2 – 1) = 2 new SCRs for heaters/boilers].

While an upgrade to one of the two recently installed SCRs at Facility 7 could occur, construction impacts associated with an SCR upgrade would be minimal, or may not be needed at all, since the equipment is currently designed to achieve a NOx concentration of five ppm. Thus, no additional analysis of an upgrade to an existing SCR for Facility 7 is needed in this SEA.

While one new SCR with an associated ammonia storage tank could be installed for the FCCU, the December 2015 Final PEA for NOx RECLAIM previously analyzed the installation of LoTOx^{TM} to the existing WGS, which estimated emissions greater than that for new installation of an SCR per Tables 4.2-13 and 4.2-15.

The remaining combustion equipment was not previously analyzed in the December 2015 Final PEA for NOx RECLAIM for Facility 7 and must be evaluated for impacts: 1) burners for six heaters/boilers will be replaced with ULNBs, and 2) two new SCR units with two new aqueous ammonia storage tanks will be installed for two heaters/boilers. This SEA updates the previous analysis in the December 2015 Final PEA for NOx RECLAIM to take into account the additional environmental impacts associated with implementing these additional activities at Facility 7.

Table 4.2-46 presents the mitigated peak daily construction emissions for Facility 7 if all of the aforementioned equipment installation and upgrade activities concurrently occur.

Table 4.2-46
Facility 7: Mitigated Peak Daily Construction Emissions for NOx Control

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Heaters/Boilers						
6 Burner Replacements with ULNBs	10.54	56.28	352.99	0.65	4.90	2.38
2 New SCRs	2.31	11.43	34.25	0.07	2.27	0.88
TOTAL	**12.85**	**67.71**	**387.24**	**0.72**	**7.17**	**3.26**
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

Operation activities associated with SCR technology are periodic ammonia deliveries, and the associated haul trips with delivering fresh catalyst and hauling away spent catalyst. The two new SCRs will be required by South Coast AQMD policy to utilize 19% aqueous ammonia. By taking a ratio of the maximum heat input rate of the heaters/boilers requiring new SCRs to the average maximum heat input rate of the heaters/boilers analyzed for the facility in the December 2015 Final PEA for NOx RECLAIM, an additional 52,586 gallons of 19% aqueous ammonia is estimated to be needed to operate the new SCRs. The additional ammonia is expected to be delivered to the facility via eight 7,000-gallon trucks per year, but no more than one round trip at 100 miles per day. One 25-ton capacity truck will be required to haul spent catalyst 260 round trip miles once every five years, and one 25-ton capacity truck will be required to deliver fresh catalyst 100 miles round-trip once every five years; however, it is assumed that only one of these trucks would operate on a given day and the greater distance is 260 round trip miles. The peak daily operational emissions for Facility 7 are presented in Table 4.2-47.

Table 4.2-47
Facility 7: Operational Emissions

Peak Daily Operational Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
1 T7 Diesel Truck for Ammonia Delivery (100 miles round-trip) + 1 T7 Diesel Truck for Catalyst Delivery/Hauling (260 miles round-trip)	0.08	3.02	0.34	0.01	0.04	0.04
South Coast AQMD Air Quality Significance Threshold for Operation	55	55	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

T7 is the EMFAC vehicle category designation for heavy-heavy duty trucks.

Facility 8

Facility 8 operates the following combustion equipment which will be subject to PR 1109.1: 10 heaters/boilers and two SRU/TGs. Tables 4.2-48 and 4.2-49 summarize the existing NOx air pollution control equipment and possible methods for achieving NOx emission reductions.

Table 4.2-48
Facility 8: Existing NOx Controls

Total Number of Equipment per Category	Equipment with LNBs	Equipment with ULNBs	Equipment with SCR	Equipment with SCR + LNBs	Equipment without NOx Control
10 Heaters/Boilers	6	-	2	-	2
2 SRU/TGs	-	-	-	-	2

Table 4.2-49
Facility 8: Potential Methods to Achieve NOx BARCT

Total Number of Equipment per Category	ULNBs	New SCR	SCR Upgrade	New SCR + ULNBs	SCR Upgrade + ULNBs	No Changes Proposed
10 Heaters/Boilers	-	3	-	3	1	3
2 SRU/TGs	-	-	-	-	-	2

For Facility 8, the December 2015 Final PEA for NOx RECLAIM previously analyzed construction and operational impacts associated with installing: 1) nine new SCRs with nine aqueous ammonia storage tanks for nine heaters/boilers; and 2) one wet gas scrubber for one SRU/TG. After the NOx RECLAIM program was amended in 2015, operators of Facility 8 installed two new SCRs with associated aqueous ammonia storage tanks for two heaters/boilers. The potential air quality impacts associated with physical modifications that may occur at Facility 8 in order to achieve the BARCT limits in PR 1109.1 were partially addressed in the December 2015 Final PEA for NOx RECLAIM.

To achieve the BARCT limits at Facility 8 for the heater/boiler category per PR 1109.1, six new SCRs with six new aqueous ammonia storage tanks could be constructed for six heaters/boilers. However, nine new SCRs and nine new ammonia storage tanks for nine heaters/boilers were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. After the NOx RECLAIM program was amended in 2015, two new SCRs with associated aqueous ammonia storage were installed. Thus, the net change in the heaters/boilers analysis for Facility 8 between the December 2015 Final PEA for NOx RECLAIM and the proposed project is that no additional analyses of new SCR installation need to be included in this SEA.

While an upgrade to one of the two recently installed SCRs at Facility 8 could occur, construction impacts associated with an SCR upgrade would be minimal, or may not be needed at all, since the equipment is currently designed to achieve a NOx concentration of five ppm. Thus, no additional analysis of these upgrades to existing SCR for Facility 8 is needed in this SEA.

The combustion equipment that was not previously analyzed in the December 2015 Final PEA for NOx RECLAIM for Facility 8 must be evaluated for impacts: burners in four heaters/boilers will be replaced with ULNBs. This SEA updates the previous analysis in the December 2015 Final PEA for NOx RECLAIM to take into account the additional environmental impacts associated with implementing these additional activities at Facility 8.

Table 4.2-50 presents the mitigated peak daily construction emissions for Facility 8 if all of the aforementioned replacement of burners with ULNBs concurrently occur.

Table 4.2-50
Facility 8: Mitigated Peak Daily Construction Emissions for NOx Control

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Heaters/Boilers						
4 Burner Replacements with ULNBs	7.03	37.52	235.33	0.43	3.27	1.58
TOTAL	**7.03**	**37.52**	**235.33**	**0.43**	**3.27**	**1.58**
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

Since the new SCRs for the heaters/boilers were previously analyzed in the December 2015 Final PEA for NOx RECLAIM, the operational impacts associated with deliveries with ammonia were also previously analyzed in the December 2015 Final PEA for NOx RECLAIM and are not repeated in this SEA. Moreover, once the ULNBs are installed for the heaters/boilers, since ULNBs do not utilize chemicals or catalyst for their operation, no additional adverse operational impacts for Facility 8, beyond what was previously analyzed in the December 2015 Final PEA for NOx RECLAIM, are expected to occur.

Facility 9

Facility 9 operates the following combustion equipment which will be subject to PR 1109.1: 19 heaters/boilers, one SRU/TG, one FCCU, and one gas turbine. Tables 4.2-51 and 4.2-52 summarize the existing NOx air pollution control equipment and possible methods to achieve NOx emission reductions.

Table 4.2-51
Facility 9: Existing NOx Controls

Total Number of Equipment per Category	Equipment with LNBs	Equipment with ULNBs	Equipment with SCR	Equipment with SCR + LNBs	Equipment without NOx Control
19 Heaters/Boilers	10	-	2	4	3
1 SRU/TG	1	-	-	-	-
1 FCCU	-	-	-	-	1
1 Gas Turbine	-	-	1	-	-

Table 4.2-52
Facility 9: Potential Methods to Achieve NOx BARCT

Total Number of Equipment per Category	ULNBs	New SCR	SCR Upgrade	New SCR + ULNBs	SCR Upgrade + ULNBs	No Changes Proposed
19 Heaters/Boilers	1	3	2	3	-	10
1 SRU/TG	1	-	-	-	-	-
1 FCCU	-	1*	-	-	-	-
1 Gas Turbine	-	-	-	-	-	1

* Alternately, a LoTOx™ with WGS, in lieu of a new SCR, may also achieve NOx BARCT for the FCCU equipment category.

For Facility 9, the December 2015 Final PEA for NOx RECLAIM previously analyzed construction and operational impacts associated with installing: 1) seven new SCRs with seven aqueous ammonia storage tanks for seven heaters/boilers; and 2) one wet gas scrubber for one FCCU. After the NOx RECLAIM program was amended in 2015, operators of Facility 9 installed four new SCRs with associated aqueous ammonia storage tanks for four heaters/boilers. The potential air quality impacts associated with physical modifications that may occur at Facility 9 in order to achieve the BARCT limits in PR 1109.1 were partially addressed in the December 2015 Final PEA for NOx RECLAIM.

To achieve the BARCT limits at Facility 9 for the heater/boiler category per PR 1109.1, six new SCRs with associated aqueous ammonia storage tanks could be constructed for six heaters/boilers. However, seven new SCRs and seven new ammonia storage tanks for seven heaters/boilers were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. After the NOx RECLAIM program was amended in 2015, four new SCRs with associated aqueous ammonia storage were installed. Thus, the net change in the heaters/boilers analysis between the December 2015 Final PEA for NOx RECLAIM and the proposed project is that three additional new SCRs with three new aqueous ammonia tanks would be installed [6 –(7 – 4) = 3 new SCRs for heaters/boilers].

Either one new SCR with an associated ammonia storage tank or one LoTOx™ with WGS could be installed for the FCCU at Facility 9. The December 2015 Final PEA for NOx RECLAIM previously analyzed the installation of LoTOx™ with WGS for the FCCU, which resulted in more construction emission impacts than what would occur if a new SCR was installed instead. See Table 4.2-13 for the previous estimates for installing a new SCR for an FCCU and Table 4.2-15 for the previous estimates for installing one LoTOx™ with WGS for an FCCU.

The combustion equipment that was not previously analyzed in the December 2015 Final PEA for NOx RECLAIM for Facility 9 must be evaluated for impacts: 1) burners in four heaters/boilers will be replaced with ULNBs, 2) three new SCR units with three new aqueous ammonia storage tanks will be installed for three heaters/boilers, 3) two existing SCR units for two heaters/boilers will be upgraded, and 4) burners in one SRU/TG will be replaced with ULNBs. This SEA updates the previous analysis in the December 2015 Final PEA for NOx RECLAIM to take into account the additional environmental impacts associated with implementing these additional activities at Facility 9.

Table 4.2-53 presents the mitigated peak daily construction emissions for Facility 9 if all of the aforementioned equipment installation and upgrade activities concurrently occur.

Table 4.2-53
Facility 9: Mitigated Peak Daily Construction Emissions for NOx Control

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Heaters/Boilers						
4 Burner Replacements with ULNBs	7.03	37.52	235.33	0.43	3.27	1.58
3 New SCRs	3.47	17.15	51.37	0.10	3.40	1.32
2 SCR Upgrades	0.57	5.58	16.57	0.04	0.81	0.23
SRU/TGTGUs						
1 Burner Replacement with ULNBs	1.76	9.38	58.83	0.11	0.82	0.40
TOTAL	**12.82**	**69.62**	**362.10**	**0.68**	**8.29**	**3.54**
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

Operation activities associated with SCR technology are periodic ammonia deliveries, and the associated haul trips with delivering fresh catalyst and hauling away spent catalyst. The three new SCRs will be required by South Coast AQMD policy to utilize 19% aqueous ammonia. One existing SCR currently utilizes anhydrous ammonia and the other existing SCR utilizes 30% aqueous ammonia; and both will be expected to continue to use their respective concentration of ammonia after the upgrades are completed; no additional ammonia, electricity, or vehicle trips will be needed. By taking the ratio of the maximum heat input rate of the heaters/boilers requiring new SCR to the average maximum heat input rate of the heaters/boilers analyzed for this facility in the December 2015 Final PEA for NOx RECLAIM, an additional 94,922 gallons of 19% aqueous ammonia will be delivered to the facility via 14 7,000-gallon trucks per year, but no more than one round-trip at 100 miles per trip per day. One 25-ton capacity truck will be required to haul spent catalyst 260 round trip miles once every five years, and one 25-ton capacity truck will be required to deliver fresh catalyst 100 miles round-trip once every five years; however, it is assumed that only one of these trucks would operate on a given day and the greater distance is 260 round trip miles. The peak daily operational emissions for Facility 9 are presented in Table 4.2-54:

Table 4.2-54
Facility 9: Operational Emissions

Peak Daily Operational Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
1 T7 Diesel Truck for Ammonia Delivery (100 miles round-trip) + 1 T7 Diesel Truck for Catalyst Delivery/Hauling (260 miles round-trip)	0.08	3.02	0.34	0.01	0.04	0.04
South Coast AQMD Air Quality Significance Threshold for Operation	55	55	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

T7 is the EMFAC vehicle category designation for heavy-heavy duty trucks.

Facility 10

Facility 10 operates the following combustion equipment which will be subject to PR 1109.1: 25 heaters/boilers, one SRU/TG, four thermal oxidizers, and one gas turbine. Tables 4.2-55 and 4.2-56 summarize the existing NOx air pollution control equipment and possible methods to achieve NOx emission reductions.

Table 4.2-55
Facility 10: Existing NOx Controls

Total Number of Equipment per Category	Equipment with LNBs	Equipment with ULNBs	Equipment with SCR	Equipment with SCR + LNBs	Equipment without NOx Control
25 Heaters/Boilers	14	-	2	6	3
1 SRU/TG	-	-	-	-	1
4 Thermal Oxidizers	3	-	-	-	1
1 Gas Turbine	-	-	1	-	-

Table 4.2-56
Facility 10: Potential Methods to Achieve NOx BARCT

Total Number of Equipment per Category	ULNBs	New SCR	SCR Upgrade	New SCR + ULNBs	SCR Upgrade + ULNBs	No Changes Proposed
25 Heaters/Boilers	-	-	-	1	-	24
1 SRU/TG	1	-	-	-	-	-
4 Thermal Oxidizers	3	-	-	-	-	1
1 Gas Turbine	-	-	-	-	-	1

Facility 10 was not previously analyzed in the December 2015 Final PEA for NOx RECLAIM; therefore, all construction and operation impacts associated with implementing the potential facility modifications to comply with the proposed project will be new emissions. One heater/boiler, one SRU/TG, and three thermal oxidizers will have their burners replaced with ULNBs, and one new SCR unit with one new aqueous ammonia storage tank for one heater/boiler will be installed.

Table 4.2-57 presents the mitigated peak daily construction emissions for Facility 10 if all of the aforementioned equipment installation and upgrade activities concurrently occur.

Table 4.2-57
Facility 10: Mitigated Peak Daily Construction Emissions for NOx Control

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Heaters/Boilers						
1 Burner Replacement with ULNBs	1.76	9.38	58.83	0.11	0.82	0.40
1 New SCR	1.16	5.72	17.12	0.03	1.13	0.44
SRU/TG						
1 Burner Replacement with ULNBs	1.76	9.38	58.83	0.11	0.82	0.40
Thermal Oxidizers						
3 Burner Replacements with ULNBs	5.27	28.14	176.50	0.33	2.45	1.19
TOTAL	**9.94**	**52.62**	**311.28**	**0.58**	**5.22**	**2.42**
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

Operation activities associated with SCR technology are periodic ammonia deliveries, and the associated haul trips with delivering fresh catalyst and hauling away spent catalyst. The new SCR will be required by South Coast AQMD policy to utilize 19% aqueous ammonia. Based on the maximum heat input rate of the heater/boiler requiring new SCR, approximately 6,486 gallons of 19% aqueous ammonia will be delivered to the facility via one 7,000-gallon truck per year, but no more than one round-trip of 100 miles per day. One 25-ton capacity truck will be required to haul spent catalyst 260 round trip miles once every five years, and one 25-ton capacity truck will be required to deliver fresh catalyst 100 miles round-trip once every five years; however, it is assumed that only one of these trucks would operate on a given day and the greater distance is 260 round trip miles. The peak daily operational emissions for Facility 10 are presented in Table 4.2-58:

Table 4.2-58
Facility 10: Operational Emissions

Peak Daily Operational Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
1 T7 Diesel Truck for Ammonia Delivery (100 miles round-trip) + 1 T7 Diesel Truck for Catalyst Delivery/Hauling (260 miles round-trip)	0.08	3.02	0.34	0.01	0.04	0.04
South Coast AQMD Air Quality Significance Threshold for Operation	55	55	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

T7 is the EMFAC vehicle category designation for heavy-heavy duty trucks.

Facility 11

Facility 11 operates the following combustion equipment which will be subject to PR 1109.1: four heaters/boilers and two thermal oxidizers and none of these are equipped with NOx emission control equipment. While no changes to four heaters/boilers are anticipated, burners in the two thermal oxidizers would need to be replaced with ULNBs.

Facility 11 was not previously analyzed in the December 2015 Final PEA for NOx RECLAIM; therefore, all construction and operation impacts associated with implementing the potential facility modifications to comply with the proposed project will be new emissions. Two thermal oxidizers will have their burners replaced with ULNBs. Table 4.2-59 presents the mitigated peak daily construction emissions for concurrently replacing the burners with ULNBs for the two thermal oxidizers at Facility 11.

Table 4.2-59
Facility 11: Mitigated Peak Daily Construction Emissions for NOx Control

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Thermal Oxidizers						
2 Burner Replacements with ULNBs	3.51	18.76	117.66	0.22	1.63	0.79
TOTAL	**3.51**	**18.76**	**117.66**	**0.22**	**1.63**	**0.79**
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

Once the ULNBs are installed for the thermal oxidizers, since ULNBs do not utilize chemicals or catalyst for their operation, no additional adverse operational impacts for Facility 11 are expected to occur.

Facilities 12 through 16

Facility 12 operates one ground flare and three sulfuric acid plants that will be subject to PR 1109.1. Due to their low use, the ground flare and two sulfuric acid plants would qualify for the low use exemption under PR 1109.1 such that no new NOx emission control equipment would need to be installed. The other sulfuric acid plant is equipped with low-NOx burners and can meet the proposed 30ppm NOx limit; the operator for facility 12 will need to submit an application to the South Coast AQMD so that the 30ppm NOx limit can be included as an enforceable permit condition.

Facilities 13, 14, and 15 each operate one SMR heater with one SCR each. While these SMR heaters will be subject to PR 1109.1, no changes to the existing SCRs will be needed. Two SMR heaters with SCR are already permitted with a 5ppm NOx limit which meets BARCT. The other SMR heater with SCR currently performs at 7.5ppm NOx, meeting the proposed conditional NOx limit for SMR heaters; the operator for this unit will need to submit an application to the South Coast AQMD so that the conditional NOx limit can be included as an enforceable permit condition.

Facility 16 operates four heaters/boilers which will be subject to PR 1109.1. Two of the four heaters/boilers are equipped with LNB burners. All four heaters/boilers are approaching the end of their useful life and will likely be replaced in the future with emerging technology. Emerging technology is technology that can achieve NOx emission reductions but is not widely available at the time the NOx limits were established in PR 1109.1. The NOx emission reduction abilities of emerging technology have not yet been demonstrated to be achieved in practice, and as such, is considered emerging because it is under development. For this reason, PR 1109.1 neither requires the use of emerging technology nor relies on the potential associated NOx emission reductions to achieve BARCT. Instead, combustion equipment with the future potential to be replaced or retrofitted with emerging technology have been allowed additional time for the emerging technology to fully mature after which a re-evaluation of its feasibility will be conducted. For example, process heaters and boilers rated at less than 40 MMBTU/hr, the ClearSign™ and John Zink's Solex™ technologies were considered promising as the next generation of ULNB technology that may be able to achieve the desired reductions in NOx emissions. Provided that these emerging technologies can demonstrate their effectiveness in achieving NOx emission reductions for refinery applications, PR 1109.1 contains a provision for process heaters rated at less than 40 MMBTU/hr to achieve a NOx limit of 9 ppm at a future date (e.g., 10 years after rule adoption and when 50% or more of the burners are replaced) and boilers rated than 40 MMBTU/hr when 50% or more of the burners are replaced. While the next generation of emerging technology may involve similar or less environmental impacts than the analysis of the NOx control technologies analyzed in this SEA, due to uncertainty as to which emerging control technology or technologies will ultimately be available and used, further analysis of emerging technologies in this SEA would be speculative. Thus, this SEA does not contain an analysis of construction and operation impacts, or the potential NOx emission reduction benefits, that may be associated with the future use of emerging technologies.

Total Construction and Operation Emissions

Given the duration of construction that would be needed to install or retrofit equipment, and the length of time provided to comply with the requirements of PR 1109.1, the construction and operation phases for multiple equipment at multiple facilities could overlap. Table 4.2-60 presents a summary of the mitigated peak-daily construction emissions associated with implementing PR

1109.1 by concurrently replacing burners with ULNBs in various combustion equipment, installing 20 new SCRs, and upgrading seven existing SCRs at all 16 affected facilities, equipment not previously analyzed in the December 2015 Final PEA for NOx RECLAIM as outlined in Table 4.2-3. This represents the worst-case scenario where all installations and retrofit projects at all facilities are conducted simultaneously. Due to limited resources such as contractors and materials, all facilities are not likely to perform construction activities at the same time. In addition, due to the prioritization of certain projects and their ability to achieve NOx emission reductions combined with the costs of undertaking these projects, each affected facility will not likely perform all installation and retrofit projects for their equipment simultaneously. NOx benefits are derived from the operation of ULNBs and air pollution control equipment, so while construction phases for certain equipment may still be ongoing, for the individual facilities that are able to complete their NOx emission projects earlier in the overall implementation timeline, incremental NOx emission reductions will be expected to occur which may help offset emissions of construction-related NOx at other facilities undergoing construction.

Table 4.2-60
Total Mitigated Peak Daily Construction Emissions for NOx Control at all 16 Facilities for PR 1109.1

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Facility 1	~~28.14~~ 24.25	~~122.87~~ 184.80	~~682.49~~ 658.88	~~1.31~~ 1.28	~~25.30~~ 35.78	~~9.38~~ 10.94
Facility 2[a]	0	0	0	0	0	0
Facility 3	~~5.27~~ 3.51	~~28.14~~ 18.76	~~176.50~~ 117.66	~~0.33~~ 0.22	~~2.45~~ 1.63	~~1.19~~ 0.79
Facility 4	~~48.64~~ 31.20	~~209.99~~ 346.34	~~1103.97~~ 551.04	~~2.16~~ 1.24	~~48.14~~ 93.69	~~17.24~~ 24.48
Facility 5	28.35	151.26	883.30	1.64	15.24	6.98
Facility 6	21.64	114.61	681.40	1.26	11.25	5.24
Facility 7	12.85	67.71	387.24	0.72	7.17	3.26
Facility 8	7.03	37.52	235.33	0.43	3.27	1.58
Facility 9	12.82	69.62	362.10	0.68	8.29	3.54
Facility 10	9.94	52.62	311.28	0.58	5.22	2.42
Facility 11	3.51	18.76	117.66	0.22	1.63	0.79
Facilities 12-16[b]	0	0	0	0	0	0
TOTAL	**~~178.18~~ 155.10**	**~~873.10~~ 1062.01**	**~~4941.27~~ 4305.90**	**~~9.34~~ 8.28**	**~~127.95~~ 183.15**	**~~51.62~~ 60.04**
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**YES**	**YES**	**YES**	**NO**	**~~NO~~ YES**	**~~NO~~ YES**

[a] The construction emissions for Facility 2 were previously analyzed in December 2015 Final PEA for NOx RECLAIM and no additional or different construction than what was previously analyzed, would be required as a result of implementing PR 1109.1.

[b] For Facilities 12 through 16, none of the combustion equipment that are subject to PR 1109.1 were identified as requiring modifications. As such, no changes are proposed at this time that would cause any construction impacts.

For context, Table 4.2-61 presents a summary of the mitigated peak-daily construction emissions associated with implementing the December 2015 Final PEA for NOx RECLAIM for the refinery sector.

Table 4.2-61
Total Mitigated* Peak Daily Construction Emissions for NOx Control at 9 Refinery Facilities as analyzed in the December 2015 Final PEA for NOx RECLAIM

Mitigated Peak Daily Construction Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Facility 1	56	209	338	0.41	130	65
Facility 2	36	104	233	0.20	30	12
Facility 3	8	42	42	0.08	40	21
Facility 4	44	146	275	0.28	70	33
Facility 5	72	270	449	0.65	152	78
Facility 6	66	250	404	0.55	151	77
Facility 7	16	84	83	0.17	61	33
Facility 8	48	167	296	0.33	90	44
Facility 9	44	146	275	0.28	89	42
Total	**389**	**1,417**	**2,396**	**2.97**	**814**	**405**
South Coast AQMD Air Quality Significance Threshold for Construction	75	100	550	150	150	55
Exceed Significance?	**YES**	**YES**	**YES**	**NO**	**YES**	**YES**

Source: See Table 4.2-10 of the December 2015 Final PEA for NOx RECLAIM.
*Mitigation only includes standard fugitive dust controls applied to PM10 and PM2.5 estimates pursuant to South Coast AQMD Rule 403.

The individual projects that each facility operator chooses to implement pursuant to the NOx BARCT standards in PR 1109.1 are expected to increase the severity of the significant effects from construction that were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Significant adverse construction impacts are therefore expected from the proposed project and mitigation measures are required.

As part of certifying the December 2015 Final PEA for NOx RECLAIM, the South Coast AQMD Governing Board adopted a mitigation monitoring plan which included mitigation measures specific to air quality impacts during construction and these mitigation measures will continue to apply to the proposed project analyzed in this SEA.[7] Specifically, the following construction mitigation measures were required for each of the affected facilities whose operators chose to install NOx control equipment pursuant to the December 2015 amendments to the NOx RECLAIM program. Similarly, at the time when each facility-specific project is proposed in response to the requirements in PR 1109.1 which are evaluated in this SEA, South Coast AQMD staff will conduct a CEQA evaluation of the facility-specific project and determine if the project is either covered by the analysis in this SEA or the previous analysis in the December 2015 Final PEA for NOx RECLAIM.

In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing South Coast AQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by South Coast AQMD personnel.

AQ-1 Develop a Construction Emission Management Plan for each affected facility to minimize emissions from vehicles including, but not limited to: consolidating truck deliveries; scheduling deliveries to avoid peak hour traffic conditions; describing truck routing; describing deliveries including logging delivery times; describing entry/exit points; identifying locations of parking; identifying construction schedule; and prohibiting truck idling in excess of five consecutive minutes or another time-frame as allowed by the California Code of Regulations, Title 13 Section 2485 - CARB's Airborne Toxic Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling. The Construction Emission Management Plan shall be submitted to South Coast AQMD CEQA for approval prior to the start of construction. At a minimum the Construction Emission Management Plan would include the following types of mitigation measures.

AQ-2 All construction equipment must be tuned and maintained in compliance with the manufacturer's recommended maintenance schedule and specifications that optimize emissions without nullifying engine warranties. All maintenance records for each equipment and their construction contractor(s) should be made available for inspection and remain onsite for a period of at least two years from completion of construction.

AQ-3 Survey and document the proposed project's construction areas and identify all construction areas that are served by electricity. Onsite electricity, rather than temporary power generators, shall be used in all construction areas that are demonstrated to be served by electricity. This documentation shall be provided as part of the Construction Emissions Management Plan.

AQ-4 Require construction equipment such as concrete/industrial saws, pumps, aerial lifts, material hoist, air compressors, forklifts, excavator, wheel loader, and soil compactors be electric or alternative-fueled (i.e., non-diesel).

AQ-5 All off-road diesel-powered construction equipment greater than 50 hp shall meet Tier-4 off-road emission standards at a minimum. In addition, if not already supplied with a factory-equipped diesel particulate filter, all construction equipment shall be

7 South Coast AQMD, Attachment 1 to the Governing Board Resolution for the Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), Findings, Statement of Overriding Considerations and Mitigation Monitoring Plan. December 2015. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2015/regxxfindings.pdf

outfitted with Best Available Control Technology (BACT) devices certified by CARB. Any emissions control device used by the contractor shall achieve emissions reductions that are no less than what could be achieved by a Level 3 diesel emissions control strategy for a similarly sized engine as defined by CARB regulations. Construction equipment shall incorporate, where feasible, emissions-reducing technology such as hybrid drives and specific fuel economy standards. In the event that any equipment required under this mitigation measure is not available, the project proponent shall provide documentation in the Construction Emissions Management Plan or associated subsequent status reports as information becomes available.

AQ-6 Suspend use of all construction activities that generate air pollutant emissions during first stage smog alerts.

If, at the time when each facility-specific project is proposed in response to the proposed project, that improved emission reduction technologies become available for on- and off-road construction equipment, as part of the CEQA evaluation for the facility-specific project, the construction mitigation measures will be updated accordingly.

If the total emissions for each criteria pollutant in Tables 4.2-60 and 4.2-61 were summed together, adverse construction impacts would continue to be significant, and more severe, even after mitigation for VOC, CO, NOx, PM10, and PM2.5 is factored into the calculations. **Therefore, the proposed project would result in significant unavoidable impacts during construction.**

Table 4.2-62 summarizes the peak daily operational emissions associated with implementing PR 1109.1 if the maximum daily truck trips at all 16 affected facilities were to overlap.

Table 4.2-62
Total Peak Daily Operation Emissions from Implementing PR 1109.1

Peak Daily Operational Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Facility 1	0.08	3.02	0.34	0.01	0.04	0.04
Facility 2[a]	0	0	0	0	0	0
Facility 3[a]	0	0	0	0	0	0
Facility 4	0.08	3.02	0.34	0.01	0.04	0.04
Facility 5	0.06	2.18	0.25	0.01	0.03	0.03
Facility 6	0.08	3.02	0.34	0.01	0.04	0.04
Facility 7	0.08	3.02	0.34	0.01	0.04	0.04
Facility 8[a]	0	0	0	0	0	0
Facility 9	0.08	3.02	0.34	0.01	0.04	0.04
Facility 10	0.08	3.02	0.34	0.01	0.04	0.04
Facilities 11-16[b]	0	0	0	0	0	0
Minimum Estimated NOx Emission Reductions		-14,000[c]				
TOTAL	**0.55**	**-13,980**	**2.31**	**0.07**	**0.28**	**0.26**
South Coast AQMD Air Quality Significance Threshold for Operation	55	55	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

a The operational emissions for Facilities 2, 3, and 8 were previously analyzed in December 2015 Final PEA for NOx RECLAIM and no additional or different operation activities than what was previously analyzed, would be required as a result of implementing PR 1109.1.

b For Facility 11, there are no operational impacts associated with operating combustion equipment fitted with ULNBs. For Facilities 12 through 16, none of the combustion equipment that are subject to PR 1109.1 were identified as requiring modifications. As such, no changes are proposed at this time that would cause any operation impacts.

c PR 1109.1 is projected to achieve seven to eight tons per day of NOx emission reductions. So as to not underestimate the overall impacts, the minimum estimated NOx emission reductions of seven tons per day was applied and this amount translates to 14,000 pounds per day.

The operation of air pollution control equipment under PR 1109.1 is expected to increase the severity of the operational impacts that were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. However, the proposed project is also anticipated to reduce NOx emissions from seven to eight tons per day, which will fully offset any increases of NOx during operation.

For context, Table 4.2-63 summarizes the peak daily operational emissions associated with implementing the December 2015 Final PEA for NOx RECLAIM for the refinery sector. Although the peak daily operational emissions exceeded the South Coast AQMD air quality significance threshold of 55 pounds per day for NOx, the project evaluated in the December 2015 Final PEA for NOx RECLAIM would achieve far greater NOx emission reductions; therefore, **the peak daily operational emissions were concluded to be less than significant overall**.

Table 4.2-63
Total Peak Daily Operational Emissions from NOx Control at 9 Refinery Facilities as analyzed in the December 2015 Final PEA for NOx RECLAIM

Mitigated Peak Daily Operational Emissions	VOC (lb/day)	NOx (lb/day)	CO (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
December 2015 Final PEA for NOx RECLAIM: Total	15	153	67	0	17	16
Estimated NOx Reductions from Surrendering NOx RTCs and/or installing NOx Controls		**-24,000[a]**				
December 2015 Final PEA for NOx RECLAIM: Total	**15**	**-23,847**	**67**	**0**	**17**	**16**
South Coast AQMD Air Quality Significance Threshold for Operation	55	55	550	150	150	55
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

Source: See Table 4.2-20 of the December 2015 Final PEA for NOx RECLAIM.

[a] The analysis in the December 2015 Final PEA for NOx RECLAIM was based on achieving 14 tons per day of NOx emission reductions via facilities surrendering NOx RTCs or installing NOx emission controls. However, the South Coast AQMD Governing Board revised the project to achieve 12 tons per day of NOx emission reductions. As such, 12 tons per day translates to 24,000 pounds per day.

Even with the total emissions for each criteria pollutant in Tables 4.2-62 and 4.2-63 were summed together, the projected NOx emissions reductions from the proposed project (e.g., seven to eight tons per day) as well as the 12 tons per day of NOx emission reductions achieved as part of adopting the December 2015 amendments to the NOx RECLAIM program, the overall operational impacts would be less than significant. Mitigation measures are not required for operation.

The maximum health risk resulting from diesel particulate matter in the exhaust of diesel-fueled heavy-duty trucks delivering and hauling supplies for one facility as a result of PR 1109.1 was determined to be 0.0015 in one million. The maximum health risk calculated in the December 2015 Final PEA for NOx RECLAIM for the same category of TAC emissions was 1.5 in one million. Therefore, at one facility, the combined health risk would be about 1.5 in a million, less than the significance threshold of 10 in a million. **The proposed project will have less than significant impacts for health risk.**

Regional PM2.5 Impacts from Ammonia Slip

In an SCR system, the ammonia or urea is injected into the flue gas stream and reacts with NOx to form elemental nitrogen (N_2) and water in the cleaned exhaust gas. ~~A small~~Some amount of unreacted ammonia ~~(ammonia slip)~~ may react with SOx in the refinery fuel gas that is burned by the boiler or process heater to form ammonium sulfate that is emitted directly from the unit, or may pass through as ammonia slip. The South Coast AQMD through permit conditions, limits ammonia slip to five ppm. In the December 2015 Final PEA for NOx RECLAIM, South Coast AQMD staff conducted a series of regional simulations to determine the impacts of reducing NOx while increasing the potential for creating ammonia slip due to increased use of ammonia needed for the operation of SCR systems. In the analysis, 14 tons per day of NOx emission reductions at RECLAIM facilities were estimated, with NOx emission reductions of 9.58 tons per day from the refinery sector and 4.42 tons per day from facilities in the non-refinery sector, and an increase of 1.63 tons per day ammonia slip emissions from the same facilities . In 2015, simulations were run for the 2021 draft baseline emissions inventory to estimate what the regional benefit would be at full implementation of the achieving 14 tons per day of NOx emission reductions. The effect of decreasing 14 tons per day of NOx would result in a decrease of annual PM2.5 concentration of approximately 0.7 µg/m^3. However, since the usage of ammonia is necessary to achieve the NOx emission reductions (primarily via SCR technology and to a lesser extent via UltraCat™ with DGS), the ammonia usage would cause a regional concurrent increase in annual PM2.5 concentration of approximately 0.6 µg/m^3. Thus, even with a potential increase in PM2.5 concentration attributable to the projected ammonia slip, the regional annual PM2.5 concentration would be reduced by 0.1 µg/m^3 overall. Further, the simulations demonstrated that there would be no change in ozone levels compared to what would occur if there was no increase in ammonia slip. The overall decrease in annual PM2.5 concentration would occur as long as 14 tons per day of NOx emissions would be reduced, even if there was an uptick in the regional concentration of PM2.5 emissions due to ammonia slip and ammonium sulfate. In summary, the impacts to regional PM2.5 and ozone concentrations due to increased ammonia slip in the simulations conducted for the analysis in the December 2015 Final PEA for NOx RECLAIM was concluded to not create a significant adverse air quality impact.

While the analysis of the environmental impacts in the December 2015 Final PEA for NOx RECLAIM was based on what physical modifications that would need to be made at the affected facilities in order to achieve the entire 14 tons per day of NOx emission reductions, including the estimates of ammonia usage and ammonia slip, the South Coast AQMD Governing Board adopted a revised version of the NOx RECLAIM proposal with a reduced NOx RTC shave amount of 12 tons per day, weighted for BARCT, and a delayed implementation schedule. Note that these tonnage totals are for the entire RECLAIM universe, not just refinery-related sources. After adjusting the total NOx emission reductions from the December 2015 NOx RECLAIM amendments to 12 tons per day, the portion of NOx emission reductions was adjusted accordingly to 8.21 tons per day from the refineries and 3.79 tons per day from facilities in the non-refinery sector. Since the amount of estimated NOx reductions in the adopted December 2015 NOx RECLAIM amendments was less than what was assumed in the December 2015 Final PEA for NOx RECLAIM, the estimated ammonia slip was also less because fewer SCRs would be required. Nonetheless, the overall quantity of NOx emission reductions from the project analyzed in the December 2015 Final PEA for NOx RECLAIM were expected to result in greater reductions in regional annual PM2.5 concentrations than the corresponding increase estimated for ammonia slip.

The currently proposed project is estimated to reduce approximately seven to eight tons per day of NOx emissions as a result of implementing PR 1109.1. As with the December 2015 amendments to NOx RECLAIM, facilities affected by the currently proposed project are anticipated to make physical modifications by installing new or modifying existing air pollution control equipment in order to achieve the proposed BARCT NOx concentration limits PR 1109.1, with the majority of the modifications primarily relying on SCR technology and to a lesser extent, UltraCat™ with DGS, both of which utilize ammonia. As such, the ammonia analysis in this SEA takes into account the original projected ammonia use and ammonia slip that was previously analyzed in the December 2015 Final PEA for NOx RECLAIM for the same nine refinery facilities and adds the projected ammonia use and corresponding ammonia slip from the additional seven facilities that comprise the PR 1109.1 universe, since ammonia will be needed to operate the new SCRs and UltraCat™ with DGS installed pursuant to PR 1109.1.

The analysis in this SEA indicates that if a minimum of seven tons per day of NOx emission reductions is achieved, a corresponding reduction in the annual PM2.5 concentration of ~~0.4~~ 0.35 μg/m^3 would result. The analysis in this SEA also indicates that implementation of the proposed project is estimated to generate ~~0.625~~ 0.647 ton per day of ammonia slip. Once in the atmosphere, emissions of ammonia slip from the proposed project are projected to chemically convert to a regional annual increase in PM2.5 concentration of ~~0.23~~ 0.24 μg/m^3. **To achieve up to eight tons per day of NOx emission reductions for the proposed project overall, a corresponding regionwide net decrease in PM2.5 concentration of ~~0.12~~ 0.11 μg/m^3 on an annual average is projected to occur**.

Odor Impacts

The CEQA significance threshold for odor is whether the project creates an odor nuisance. During construction, there will be odors associated with the operation of diesel-fueled off-road construction equipment used to install new or upgrade existing SCR systems, install LoTOx™ with and without a WGS, install UltraCat™ with DGS, and replace existing burners with ULNBs in various combustion equipment.. In addition, diesel-fueled on-road vehicles may be utilized during both construction and operation activities at the facilities and these vehicles will be required to use diesel fuel with a low sulfur content (e.g., 15 ppm by weight or less) in accordance with South Coast AQMD Rule 431.2 - Sulfur Content of Liquid Fuels. Heavy-duty trucks are prohibited from idling for more than five minutes at any one location as regulated by the Airborne Toxic Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling, but they can move to multiple locations and idle at each location for up to five minutes; so lingering odors would not be expected from these vehicles. Finally, because of the relatively small number of pieces of diesel-fueled on- and off-road equipment being utilized at any one site and because construction will only be short-term, odor impacts noticeable outside of each facility's property boundaries are not expected to be significant.

Once the new SCR and UltraCat™ with DGS systems are installed and operational, the amount of ammonia used by these air pollution control technologies will increase. However, new SCR and UltraCat™ with DGS systems will be required to meet a BACT limit for ammonia which is currently five ppm. Because the exhaust gases are hot, any ammonia slip emissions from operating a SCR or UltraCat™ with DGS would be quite buoyant and would rapidly rise to higher altitudes without any possibility of lingering at ground level. Organizations differ on what the odor threshold of ammonia is: up to 46.8 ppm according to the US Coast Guard, 0.04 to 20 ppm according the American Association of Railroads, and 5 to 50 ppm according to OSHA.[8] **Because BACT limits ammonia to five ppm which is on the low end of odor thresholds, the buoyancy of ammonia emissions causes it to rapidly rise, and there is an average prevailing wind velocity of six miles per hour in the Basin, it is unlikely that ammonia slip emissions would cause an odor nuisance during operation, and this project will cause a less than significant increase to odor.**

In addition to PR 1109.1, the proposed project includes adopting PR 429.1, amending PARs 1304 and 2005 and rescinding Rule 1109. As explained in the following discussion, a review of the

[8] https://www.osha.gov/sites/default/files/2019-03/fs5-howsmelly.pdf

requirements in PR 429.1 and PARs 1304 and 2005 as well as rescinding Rule 1109 shows that none of those actions will have a significant adverse impact on the environment.

Proposed Rescission of Rule 1109

The proposed project includes the rescission of existing Rule 1109. Rule 1109 was originally adopted in 1984 but has been inapplicable since 1993 when the RECLAIM program was adopted. RECLAIM Rule 2001 - Applicability, Table 1, lists all of the rules that do not apply to RECLAIM facilities and includes Rule 1109. All of the facilities originally subject to Rule 1109 (boilers and process heaters at refineries) are currently in the RECLAIM program. Therefore, rescinding Rule 1109 will have no effect on the environment since it be outdated once it is replaced by PR 1109.1, whose adoption is being analyzed in this SEA for potential environmental effects.

PAR 1304

PAR 1304 is part of South Coast AQMD's New Source Review program for nonattainment pollutants and their precursors. New Source Review for non-RECLAIM pollutants is established in Regulation XIII, while New Source Review for RECLAIM pollutants is established in Rule 2005. One element of the new Source Review program is a requirement that new or modified sources of pollution install BACT for any pollutants for which there is an emissions increase. PAR 1304 would provide a limited exemption from BACT for projects undertaken to comply with PR 1109.1.

The reason for the proposed exemption is that some projects that implement PR 1109.1, such as the installation of SCR technology to reduce NOx emissions from some boilers and process heaters, can result in increases in particulate matter. SCR technology relies on the use of ammonia in the process of reducing NOx and a small amount of ammonia, referred to as "ammonia slip" escapes rather than being taken up in the chemical reaction that reduces NOx. The ammonia reacts with SOx in the refinery fuel gas that is burned by the boiler or process heater to form ammonium sulfate, which is a type of particulate matter (PM10) and a pollutant regulated by Rule 1304. Currently, if a modification results in any increase of PM10, BACT for PM10 is required. South Coast AQMD engineering staff has determined that for units burning refinery fuel gas, BACT for PM10 is achieving a sulfur content limit in the refinery fuel gas that is typically lower than existing sulfur concentrations at refineries. . The added cost of installing additional equipment to meet this PM10 BACT requirement may not be cost-effective in some cases. To enable covered facilities to reach the low levels of NOx required by PR 1109.1, it is necessary to provide limited relief from this specific PM10 BACT requirement. Accordingly, PAR 1304 would provide an exemption from BACT for PM10 for projects implemented to comply with a BARCT requirement adopted before December 31, 2023. It should be noted that air districts throughout California currently include a similar exemption from New Source Review requirements when operators are complying with a BARCT rule.

In theory, providing a limited PM10 BACT exemption could potentially allow greater emissions of PM10 than would occur without the exemption. However, in reality, the projects to which the exemption will apply would not occur unless PR 1109.1 is adopted. Under RECLAIM, the system that would be in effect without the adoption of PR 1109.1, even if emission reduction projects were implemented, they would not trigger this BACT requirement and thus, would not result in sulfur clean-up and associated PM10 reductions. Under RECLAIM, facilities would have the option of either choosing to purchase RTCs and/or to implement only projects that affect natural gas-fired units which do not cause a PM10 increase because natural gas does not have the same high levels of sulfur as refinery fuel gas, or they may choose projects which do not result in an overall increase of PM10 emissions of one pound per day or more and therefore, do not trigger PM10 BACT. Therefore, there would be no projects to which the BACT requirement would apply absent PR 1109.1, and no projects that would reduce the sulfur in refinery fuel gas. So, compared to not adopting PAR 1304 , the proposed project would not result in PM10 increases. Moreover, NOx is a precursor to PM10, so reducing NOx emissions reduces PM10 as well as ozone. Therefore, the project as a whole causes a PM10 benefit, and not a significant adverse impact to PM10. In addition, the analysis for the proposed project shows a net regionwide decrease in annual PM2.5 concentrations due to the large quantity of NOx emissions reductions expected to be achieved (e.g., seven to eight tons per day), even with ammonia slip from the use of SCR technology. (See the discussion in Regional PM2.5 Impacts from Ammonia Slip earlier in this chapter.)

PAR 2005

In some cases, a facility may choose to replace existing equipment rather than install add-on NOx controls. Newer equipment is generally cleaner, more efficient, and produces less emissions than the equipment it is replacing. However, in the context of New Source Review, equipment replacement is treated as though it were the installation of new equipment, and all emissions are considered new. Therefore, emissions from the replaced equipment will trigger BACT for any pollutant emitted. In some cases, facilities may be replacing equipment that is fired on refinery fuel gas. Since refinery fuel gas contains sulfur, there would be a calculated increase in SOx emissions and SOx is a pollutant regulated under Rule 2005 - New Source Review for RECLAIM. BACT would be required for SOx. As with BACT for PM10, BACT for SOx under these circumstances would also require modifications necessary to reduce the sulfur content in the refinery fuel gas.

However, based on the preceding discussion, requiring sulfur clean-up would make the NOx reductions to be achieved by PR 1109.1 not cost-effective in some cases. Accordingly, an exemption is proposed in PAR 2005 to address RECLAIM SOx BACT. It should be noted that there may not be any real increase in SOx emissions because the new equipment generally has fewer emissions than the equipment it is replacing.

As with PAR 1304, however, the emissions decrease resulting from sulfur in the refinery fuel gas will not actually occur under RECLAIM because facilities, even if they installed emission reduction projects, would not select replacement projects that would require sulfur reductions in the refinery fuel gas. Therefore, the BACT exemption proposed in PAR 2005 would not result in an actual increase in SOx emissions.

PR 429.1

PR 429.1 would provide exemptions from the NOx and CO limits under PR 1109.1 when units are starting up or shutting down, and during certain maintenance activities. NOx concentration limits established under PR 1109.1 are based on when the unit has reached steady-state operation and the air pollution control equipment is operational. During start-up and shutdown events, units have not reached steady-state conditions; temperatures needed for post-combustion NOx controls such as SCR must reach minimum temperatures in order to be able to reduce NOx emissions to levels that are capable of achieving the NOx limits under PR 1109.1. Although some units have permit conditions that limit the timeframe that emissions are exempt during start-up, shutdown, and certain maintenance activities, U.S. EPA has commented that specific requirements when an operator is exempt from the NOx limits in PR 1109.1 must be included in a rule such as PR 429.1.

Implementation of PR 1109.1 and PR 429.1 will not increase CO emissions. Currently, some facilities have permit conditions that limit the duration of start-up and shutdown events. The operator must adhere to the more stringent provisions for startup and shutdown events that are in either PR 429.1 or their permit. Thus, implementation of PR 429.1 will either be more stringent or equally as stringent as the existing regulatory structure. As a result, there are no significant adverse air quality impacts related to CO if PR 429.1 is adopted. In addition, installation of SCR technology is not expected to increase CO emissions from the unit, and the CO emissions during start-up and shutdown would not be expected to change.

Regarding NOx, prior to the adoption of the RECLAIM program in 1993, refineries were subject to Rule 1109 which established NOx limits for large boilers and heaters. Similar to PR 1109.1 and PR 429.1, refineries subject to Rule 1109 were also subject to Rule 429, which contains start-up and shutdown provisions. Rule 429 which was adopted in 1990, exempted refineries from the NOx limits in Rule 1109 during start-up and shutdown events. Since RECLAIM did not establish NOx limits, exemptions from NOx limits during start-up and shutdown provisions were no longer needed. As a result, start-up and shutdowns were not limited by the number per year or the duration of the start-up or shutdown event. PR 429.1 is more restrictive than the current regulatory regime since it limits the duration of start-up and shutdown events and the number of scheduled start-up and shutdown events each year, which does not currently exist under RECLAIM. Thus ,PR 429.1 would reduce NOx emissions compared to the RECLAIM program.

However, RECLAIM requires NOx emissions, including those resulting from start-ups and shutdowns, to be offset by providing RTCs, which represent emission reductions. Therefore, it could be argued that PR 429.1 allows a NOx increase on a regional basis. It is difficult to quantify the peak daily emissions that might result from a start-up or shutdown, but as explained in the staff report for PR 429.1, most affected units undergo start-ups and shutdowns infrequently. It is not reasonably foreseeable that all units affected by PR 429.1 would undergo start-ups or shut-downs on the same day. Start-ups and shutdowns that are exempt from PR 1109.1 limits will occur only during the operational phase of the project, when NOx emission reductions have been implemented. Although the NOx concentration levels during start-up and shutdown periods may exceed the limits in PR 1109.1, the mass emissions are not expected to be substantially higher as the unit will be at a much lower capacity as the unit is either starting up or shutting down. Although PR 429.1 allows multiple start-up and shutdown events per unit, refineries limit their scheduled start-up and shutdown events to minimize operational disruptions. Start-up and shutdown events at petroleum refineries are generally associated with turnaround cycles which tend to be once every three to five years, and up to nine to 10 years for certain units such as crude units. Even if two scheduled shutdowns were assumed for the units with the longest start-up and shutdown allowance of 120 hours, the exemption in PR 429.1 would apply to five percent of the unit's operating hours and 95 percent of the unit's operating hours would be subject to the PR 1109.1 NOx and CO limits. In addition, it is expected that the NOx emission reductions from each phase of PR 1109.1 implementation will substantially exceed any increased emissions due to the exemption for NOx in PR 429.1.

4.2.3 Cumulative Air Quality Impacts

Pursuant to CEQA Guidelines Section 15130(a), the SEA shall discuss cumulative impacts of a project when the project's incremental effect is cumulatively considerable. In general, the preceding analysis concluded that air quality impacts from construction activities would be significant from implementing the proposed project because the South Coast AQMD's significance thresholds for construction will be exceeded even after mitigation is applied. Thus, the air quality impacts due to construction are considered to be cumulatively considerable pursuant to CEQA Guidelines Section 15064(h)(1) and therefore, generate significant adverse cumulative air quality impacts. It should be noted, however, that the air quality analysis is a conservative, "worst-case" analysis so the actual construction impacts are not expected to be as great as estimated here. Further, the construction activities are temporary when compared to the permanent projected long-term emission reductions of NOx as a result of the proposed project.

The analysis also indicates that the proposed project will result in less than significant increases of all criteria air pollutants during the operational phase of the proposed project due to the overall substantial reduction in NOx emissions. There will also be less than significant increases to health risk and odor. Pursuant to CEQA Guidelines Section 15130(a)(2), when the combined cumulative impact associated with the project's incremental effect is not significant, the SEA must indicate why the cumulative impact is not significant. Because operational emissions do not exceed the air quality significance thresholds, which also serve as the cumulative significance thresholds, they are not considered to be cumulatively considerable [CEQA Guidelines Section 15064 (h)(1)].

This identical standard is appropriate because the South Coast AQMD air quality significance thresholds for criteria pollutants were set by evaluating the effect an individual project may have on the ability of the South Coast Air Basin to attain the NAAQS established by the U.S. EPA, and are therefore, cumulative in nature. Specifically, the South Coast AQMD Governing Board adopted 1993 CEQA Air Quality Handbook, which identified that the thresholds for criteria pollutants are based on the emissions levels in the Clean Air Act for a major source in an area designated as extreme non-attainment for ozone. [1993 CEQA Handbook, Chapter 6]. So, for example, a major source of VOCs, a precursor for ozone, is defined as a source that has a potential to emit at least 10 tons per year of VOCs [Clean Air Act section 182(e)]. The South Coast AQMD converted the 10 tons per year in terms of pounds per day, which resulted in a significance threshold of 55 pounds per day for operational emissions. The 1993 CEQA Handbook also explains that this approach is appropriate because the regulatory framework to establish the state and federal ambient air quality standards, and the method to achieve attainment of those standards, are intended to be protective of public health.

Also, implementing Control Measure CMB-05 contained in the 2016 AQMP which includes the RECLAIM Transition project, in addition to the air quality benefits of other existing and proposed South Coast AQMD rules, is anticipated to bring the South Coast AQMD into attainment with all national and most state ambient air quality standards. Therefore, cumulative operational air quality impacts from the proposed project combined with emission reductions from previous amendments, including amendments made to the other command-and-control rules that have been amended as part of the RECLAIM Transition project, are not expected to be cumulatively significant because implementation of the proposed project is expected to result in net emission reductions and overall air quality improvement. Therefore, there will be no significant cumulative adverse operational air quality impacts from implementing the proposed project.

Though the proposed project involves combustion processes which could generate GHG emissions such as CO2, CH4, and N2O, the proposed project does not affect equipment or operations that have the potential to emit other GHGs such as SF6, HFCs, or PFCs. Relative to GHGs, implementing the proposed project is expected to increase GHG emissions that exceed the South Coast AQMD's GHG significance threshold for industrial sources. In addition, implementing the proposed project is expected to generate significant adverse cumulative GHG air quality impacts. The GHG analysis for the proposed project can be found in the Section 4.2.5 – Greenhouse Gas Impacts and Mitigation Measures.

In addition, CEQA Guidelines Section 15130 (d) states "No further cumulative impacts analysis is required when a project is consistent with a general, specific, master or comparable programmatic plan where the lead agency determines that the regional or areawide cumulative impacts of the proposed project have already been adequately addressed in section 15152(f), in a certified EIR for that plan."

The proposed project as evaluated in this SEA is consistent with the 2016 AQMP because it implements a control measure CMB-05 contained in the 2016 AQMP and analyzed in the EIR for the AQMP. The EIR for the AQMP analyzed the impacts, including cumulative impacts, from all of the control measures in the 2016 AQMP. The regional cumulative impacts of the proposed project have already been adequately addressed in the certified March 2017 Final Program EIR for the 2016 AQMP.

The 2016 AQMP is a regional plan that includes all the measures, whether regulatory or incentive-based, that are included in the AQMP to help attain the national ambient air quality standards. As such, March 2017 Final Program EIR evaluated the environmental impacts associated with implementing the 2016 AQMP stationary and mobile source control measures to determine whether or not the impacts of the project are cumulatively considerable when combined with potential impacts associated with other similar regional projects involving regulatory activities or other projects with similar impacts. The 2016 AQMP control measures consist of three components: 1) the South Coast AQMD's Stationary and Mobile Source Control Measures (which includes CMB-05 and the RECLAIM Transition project; 2) State and Federal Mobile Source Control Measures; and 3) Regional Transportation Strategy and Control Measures provided by SCAG. The cumulative impacts analysis for the March 2017 Final Program EIR also included the project-specific analyses of the South Coast AQMD's stationary and mobile source control measures and CARB's mobile source control measures, as well as the transportation control measures (TCMs) that were developed and adopted by the Southern California Association of Governments (SCAG) as part of the 2016 Regional Transportation Plan/Sustainable Communities Strategy RTP/SCS) and the 2015 Federal Transportation Improvement Program (FTIP)[9]. The TCMs are appropriately part of the cumulative impact analysis because they include regulatory activities associated with measures that could also generate related environmental impacts within the Basin. The cumulative impacts analysis was conducted for each of the CEQA topic areas. The current proposed project is consistent with and implements the AQMP Control Measure CMB-05, which was included in the previous cumulative impact analysis. This analysis adequately addressed the cumulative impacts of the proposed project. Thus, no further cumulative impacts analysis is required. [CEQA Guidelines Section 15130(d)].

[9] South Coast AQMD, 2016 AQMP, Appendix IV-C.

4.2.4 Cumulative Mitigation Measures

The analysis indicates that the proposed project will result in less than significant increases of all criteria air pollutants during the operational phase of the proposed project due to the overall substantial reduction in NOx emissions. No pollutant emissions exceed the applicable significance thresholds during operation for the proposed project. There will also be less than significant increases to health risk. Thus, there are no adverse significant cumulative air quality impacts during the operational phase of the proposed project and as such, no cumulative mitigation measures for operation are required.

Further, implementing Control Measure CMB-05 contained in the 2016 AQMP which includes the RECLAIM Transition project, in addition to the air quality benefits of other existing and proposed South Coast AQMD rules, is anticipated to bring the South Coast AQMD into attainment with all national and most state ambient air quality standards. Therefore, cumulative operational air quality impacts from the proposed project combined with emission reductions from previous amendments, including amendments made to the other command-and-control rules that have been amended as part of the RECLAIM Transition project, are not expected to be cumulatively significant because implementation of the proposed project is expected to result in net emission reductions and overall air quality improvement. Therefore, since there will be no significant cumulative adverse operational air quality impacts from implementing the proposed project, cumulative mitigation measures for operation are not required.

The analysis also suggests that VOC, NOx, CO, PM10, and PM2.5 emissions, even after mitigation is applied, will exceed the applicable significance thresholds during construction. As a result, the proposed project is expected to have significant cumulative adverse construction air quality impacts. Mitigation measures that focus on the VOC, NOx, CO, PM10, and PM2.5 emissions that may be generated during construction are required to minimize the significant air quality impacts associated with construction activities. Therefore, feasible mitigation measures to reduce emissions associated with construction activities at the affected facilities are necessary to control emissions from heavy construction equipment and worker travel. While the mitigation measures may reduce emissions associated with construction activities at the affected facilities to the maximum extent feasible, the project will not avoid the significant impact or reduce the impacts to less than significant levels.

The following construction mitigation measures are required for each of the affected facilities whose operators choose to install NOx control equipment. If, at the time when each facility-specific project is proposed in response to the proposed project, South Coast AQMD staff will conduct a CEQA evaluation of the facility-specific project and determine if the project is covered by the analysis in this SEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing South Coast AQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by South Coast AQMD personnel.

AQ-1 Develop a Construction Emission Management Plan for each affected facility to minimize emissions from vehicles including, but not limited to: consolidating truck deliveries; scheduling deliveries to avoid peak hour traffic conditions; describing truck routing; describing deliveries including logging delivery times; describing entry/exit points; identifying locations of parking; identifying construction schedule; and prohibiting truck idling in excess of five consecutive minutes or another time-frame as allowed by the California Code of Regulations, Title 13 Section 2485 - CARB's

Airborne Toxic Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling. The Construction Emission Management Plan shall be submitted to South Coast AQMD CEQA for approval prior to the start of construction. At a minimum the Construction Emission Management Plan would include the following types of mitigation measures.

AQ-2 All construction equipment must be tuned and maintained in compliance with the manufacturer's recommended maintenance schedule and specifications that optimize emissions without nullifying engine warranties. All maintenance records for each equipment and their construction contractor(s) should be made available for inspection and remain onsite for a period of at least two years from completion of construction.

AQ-3 Survey and document the proposed project's construction areas and identify all construction areas that are served by electricity. Onsite electricity, rather than temporary power generators, shall be used in all construction areas that are demonstrated to be served by electricity. This documentation shall be provided as part of the Construction Emissions Management Plan.

AQ-4 Require construction equipment such as concrete/industrial saws, pumps, aerial lifts, material hoist, air compressors, forklifts, excavator, wheel loader, and soil compactors be electric or alternative-fueled (i.e., non-diesel).

AQ-5 All off-road diesel-powered construction equipment greater than 50 hp shall meet Tier-4 off-road emission standards at a minimum. In addition, if not already supplied with a factory-equipped diesel particulate filter, all construction equipment shall be outfitted with Best Available Control Technology (BACT) devices certified by CARB. Any emissions control device used by the contractor shall achieve emissions reductions that are no less than what could be achieved by a Level 3 diesel emissions control strategy for a similarly sized engine as defined by CARB regulations. Construction equipment shall incorporate, where feasible, emissions-reducing technology such as hybrid drives and specific fuel economy standards. In the event that any equipment required under this mitigation measure is not available, the project proponent shall provide documentation in the Construction Emissions Management Plan or associated subsequent status reports as information becomes available.

AQ-6 Suspend use of all construction activities that generate air pollutant emissions during first stage smog alerts.

If, at the time when each facility-specific project is proposed in response to the proposed project, that improved emission reduction technologies become available for on- and off-road construction equipment, as part of the CEQA evaluation for the facility-specific project, the construction mitigation measures will be updated accordingly.

4.2.5 Greenhouse Gas Impacts and Mitigation Measures

Significant changes in global climate patterns have recently been associated with global warming, an average increase in the temperature of the atmosphere near the Earth's surface, attributed to accumulation of GHG emissions in the atmosphere. GHGs trap heat in the atmosphere, which in turn heats the surface of the Earth. Some GHGs occur naturally and are emitted to the atmosphere through natural processes, while others are created and emitted solely through human activities. The emission of GHGs through the combustion of fossil fuels (i.e., fuels containing carbon) in conjunction with other human activities, appears to be closely associated with global warming. State law defines GHG to include the following: carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6) (HSC Section 38505(g)). The most common GHG that results from human activity is CO2, followed by CH4 and N2O.

Traditionally, GHGs and other global warming pollutants are perceived as solely global in their impacts and that increasing emissions anywhere in the world contributes to climate change anywhere in the world. A study conducted on the health impacts of CO2 "domes" that form over urban areas cause increases in local temperatures and local criteria pollutants, which have adverse health effects[10].

The analysis of GHGs is a different analysis than the analysis of criteria pollutants for the following reasons. For criteria pollutants, the significance thresholds are based on daily emissions because attainment or non-attainment is primarily based on daily exceedances of applicable ambient air quality standards. Further, several ambient air quality standards are based on relatively short-term exposure effects on human health (e.g., one-hour and eight-hour standards). Since the half-life of CO2 is approximately 100 years, for example, the effects of GHGs occur over a longer term which means they affect the global climate over a relatively long time frame. As a result, the South Coast AQMD's current position is to evaluate the effects of GHGs over a longer timeframe than a single day (i.e., annual emissions). GHG emissions are typically considered to be cumulative impacts because they contribute to global climate effects. GHG emission impacts from implementing the proposed project were calculated at the project-specific level during construction and operation. For example, installation of NOx control equipment has the potential to increase the use of electricity, fuel, and water and the generation of wastewater which will in turn increase CO2 emissions.

The South Coast AQMD convened a "Greenhouse Gas CEQA Significance Threshold Working Group" to consider a variety of benchmarks and potential significance thresholds to evaluate GHG impacts. On December 5, 2008, the South Coast AQMD adopted an interim CEQA GHG Significance Threshold for projects where South Coast AQMD is the lead agency (South Coast AQMD, 2008). This interim threshold is set at 10,000 metric tons of CO2 equivalent emissions (MT/yr of CO2eq). The South Coast AQMD prepared a "Draft Guidance Document – Interim CEQA GHG Significance Thresholds" that outlined the approved tiered approach to determine GHG significance of projects (South Coast AQMD, 2008, pg. 3-10). The first two tiers involve: 1) exempting the project because of potential reductions of GHG emissions allowed under CEQA; and, 2) demonstrating that the project's GHG emissions are consistent with a local general plan. Tier 3 proposes a limit of 10,000 MT/yr CO2eq as the incremental increase representing a significance threshold for projects where South Coast AQMD is the lead agency (South Coast AQMD, 2008, pg. 3-11). Tier 4 (performance standards) is yet to be developed. Tier 5 allows offsets that would reduce the GHG impacts to below the Tier 3 brightline threshold. Projects with incremental increases below this threshold will not be cumulatively considerable.

[10] Jacobsen, Mark Z. "Enhancement of Local Air Pollution by Urban CO2 Domes," Environmental Science and Technology, as describe in Stanford University press release on March 16, 2010 available at: http://news.stanford.edu/news/2010/march/urban-carbon-domes-031610.html.

As indicated in Chapter 3, combustion processes generate GHG emissions in addition to criteria pollutants. The following analysis mainly focuses on directly emitted CO2 because this is the primary GHG pollutant emitted during the combustion process and is the GHG pollutant for which emission factors are most readily available. CO2 emissions were estimated using emission factors from CARB's EMFAC2017 and OFFROAD2011 models. In addition, CH4 and N20 emissions were also estimated and are included in the overall GHG calculations. No other GHGs are expected to be emitted because the proposed project does not affect equipment or operations that have the potential to emit other GHGs such as SF6, HFCs or PFCs.

Installation of NOx control equipment as part of implementing the proposed project is expected to generate construction-related CO2 emissions. In addition, based on the type and size of equipment affected by the proposed project, CO2 emissions from the operation of the NOx control equipment are likely to increase from current levels due to using electricity, fuel, and water. The proposed project will also result in an increase of GHG operational emissions produced from additional truck hauling and deliveries necessary to accommodate the additional solid waste generation and increased use of chemicals and supplies.

For the purposes of addressing the potential GHG impacts of the proposed project, the overall impacts of CO2eq emissions from the project were estimated and evaluated from the earliest possible initial implementation of the proposed project with construction beginning in 2022. While overlapping NOx RECLAIM shave projects have already begun and or completed construction, this analysis evaluates impacts from equipment not previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Once the proposed project is fully implemented, the potential NOx emission reductions would continue through the end of the useful life of the equipment. The analysis estimated CO2eq emissions from all sources subject to the proposed project (construction and operation) from the time construction is expected to commence (January 1, 2022) to the end of the project (2033-2034). The beginning of the proposed project was assumed to be no sooner than 2022, since installing NOx control equipment takes considerable advance planning and engineering. Full implementation of the proposed project is expected to occur by the end of 2033-2034 when the entire seven to eight tons per day of NOx reductions is completed such that any installed or modified NOx controls could be constructed and operational by this final date. Thus, once construction is complete and the equipment is operational, CO2eq emissions will remain constant.

GHG emissions from the 16 refinery facilities were quantified by applying the same assumptions used to quantify the criteria pollutant emissions. The only exception is that the construction GHG emissions were amortized over a 30-year project life in accordance with the guidance provided in the Interim CEQA GHG Significance Threshold for Stationary Sources, Rules and Plans[11] that was adopted by the South Coast AQMD Governing Board in December 2008.

Approximately 1,005 amortized MT/yr of GHGs as CO2eq would be generated from construction-related activities that may occur at the affected refinery facilities in response to implementing the proposed project. Similarly, approximately 14 MT/yr of GHG emissions would be generated from operation-related activities (e.g., truck trips) that may occur at the refinery facilities in response to implementing the proposed project. Lastly, because operation of all of the NOx control technologies require electricity, approximately 2,318 MT/yr of CO2eq may be generated if all

[11] Interim CEQA GHG Significance Threshold for Stationary Sources, Rules and Plans, http://www.aqmd.gov/docs/default-source/ceqa/handbook/greenhouse-gases-(ghg)-ceqa-significance-thresholds/ghgattachmente.pdf

refinery facilities install NOx control equipment. In total, 3,338 MT/yr of CO2eq emissions would be generated by construction and operation activities occurring at the nine refinery facilities, should these facility operators choose to install NOx control technology in response to the proposed project. The total incremental amount of GHG emissions that may be generated from new operation activities at refinery facilities is less than the GHG significance threshold of 10,000 MT/yr and thus, would not be considered a significant adverse GHG emissions impact if the proposed project is implemented.

Table 4.2-64a summarizes the unmitigated CO2eq impacts from both construction activities and operation activities per refinery facility if the proposed project is implemented.

Representatives from facilities 1 and 4 have indicated that they are planning to implement 11 and one emerging technology burner projects, respectively. Because this technology is not currently mature and would not be installed within the next few years as in the case of ULNB and SCR projects, air quality emissions have not been included in the peak day construction emissions analysis; however, they are included below in the GHG analysis which amortizes GHG emissions over 30 years. The GHG emissions from emerging technology burner projects is estimated to be equivalent to that of replacement with ULNB.

Table 4.2-64a
Proposed Project Overall Unmitigated CO2eq Increases Due to Construction and Operation Activities per Refinery Facility (metric tons/year)[1]

Refinery Facility ID	Temporary Construction Activities (diesel and gasoline fuel use)[2] (MT/yr)	Operational Electricity Use[3] (MT/yr)	Operational Truck Trips (diesel fuel use) (MT/yr)	Total CO2eq (MT/yr)
1	~~161~~ 219	~~374~~ 249	1	~~537~~ 469
2[4]	-	-	-	-
3	~~30~~ 19	-	-	~~30~~ 19
4	~~274~~ 122	~~311~~ 621	~~2~~ 4	~~587~~ 747
5	~~159~~ 152	136	1	~~295~~ 288
6	~~122~~ 117	439	3	~~565~~ 559
7	~~73~~ 70	180	2	~~254~~ 251
8	~~40~~ 38	-	-	~~40~~ 38
9	~~70~~ 67	324	3	~~397~~ 394
10	~~56~~ 54	79	1	~~136~~ 133
11	~~20~~ 19	-	-	~~20~~ 19
12-16[5]	-	-	-	-
TOTAL	**~~1,005~~ 875**	**~~1,842~~ 2,028**	**~~12~~ 13**	**~~2,859~~ 2,917**

1 1 metric ton (MT) = 2,205 pounds
2 GHGs from temporary construction activities are amortized over 30 years
3 The calculations conducted using CalEEMod version 2016.3.2 assume Los Angeles Department of Water and Power (LADWP) supplies electricity to all the facilities according to the utility intensity emission factor of 1,228.8 lb/MWh of CO2eq for reporting year 2007.
4 The construction emissions for Facility 2 were previously analyzed in December 2015 Final PEA for NOx RECLAIM and no additional or different construction activities generating GHGs than what was previously analyzed, would be required as a result of implementing PR 1109.1.
5 For Facilities 12 through 16, none of the combustion equipment that are subject to PR 1109.1 were identified as requiring modifications. As such, no changes are proposed at this time that would cause any construction impacts.

The GHG emission estimates presented in Table 4.2-64a were calculated using CalEEMod version 2016.3.2 for general construction and operation scenarios that did not consider each facility's unique electrical utility provider. Instead, the CalEEMod analysis applied the utility intensity emission factor of 1,228.8 pounds of CO2eq per megawatt-hour (lb/MWh) for the Los Angeles Department of Water and Power (LADWP) for reporting year 2007 for all facilities because the utility intensity emission factors for LADWP were the largest of the utility providers in Los Angeles County and thus, would ensure that the GHGs operational electricity use would not be underestimated. However, the most recent utility intensity emission factor for LADWP is 694 lb/MWh of CO2eq for reporting year 2021, which is almost a 50 percent reduction when compared to the 2007 reporting year.

In addition, only Facilities 4, 7 and 9 receive electricity from the LADWP; the remaining facilities receive electricity from Southern California Edison (SCE) which has a utility intensity emission factor of 393 lb/MWh of CO2eq for reporting year 2021.

Table 4.2-64b presents the same GHG emission estimates from Table 4.2-64a for temporary construction activities and operational truck trips, but with operational electricity use tailored for each facility's utility provider.

Table 4.2-64b
Proposed Project Overall Unmitigated CO2eq Increases Due to Construction and Operation Activities per Refinery Facility (metric tons/year)[1] with Updated Utility Intensity Emission Factors for Operational Electricity Use

Refinery Facility ID	Temporary Construction Activities (diesel and gasoline fuel use)[2] (MT/yr)	Operational Electricity Use[3] (MT/yr)	Operational Truck Trips (diesel fuel use) (MT/yr)	Total CO2eq (MT/yr)
1	~~161~~ 219	~~209~~ 139	1	~~372~~ 359
2[4]	-	-	-	-
3	~~30~~ 19	-	-	~~30~~ 19
4	~~274~~ 122	~~175~~ 351	~~2~~ 4	~~452~~ 476
5	~~159~~ 152	76	1	~~235~~ 228
6	~~122~~ 117	246	3	~~371~~ 365
7	~~73~~ 70	102	2	~~176~~ 173
8	~~40~~ 38	-	-	~~40~~ 38
9	~~70~~ 67	183	3	~~256~~ 253
10	~~56~~ 54	44	1	~~101~~ 98
11	~~20~~ 19	-	-	~~20~~ 19
12-16[5]	-	-	-	-
TOTAL	**~~1,005~~ 875**	**~~1,035~~ 1,140**	**~~12~~ 13**	**~~2,051~~ 2,029**

1 1 metric ton (MT) = 2,205 pounds
2 GHGs from temporary construction activities are amortized over 30 years
3 The calculations for operational electricity use are tailored for each facility's electricity provider which is either LADWP with a utility intensity emission factor of 694 lb/MWh of CO2eq for reporting year 2021 or SCE with a utility intensity emission factor of 393 lb/MWh of CO2eq for reporting year 2021.
4 The construction emissions for Facility 2 were previously analyzed in December 2015 Final PEA for NOx RECLAIM and no additional or different construction activities generating GHGs than what was previously analyzed, would be required as a result of implementing PR 1109.1.

[5] For Facilities 12 through 16, none of the combustion equipment that are subject to PR 1109.1 were identified as requiring modifications. As such, no changes are proposed at this time that would cause any construction impacts.

For context, Table 4.2-65a presents a summary of the unmitigated CO2eq increases due to construction and operation activities associated with implementing the December 2015 Final PEA for NOx RECLAIM for the refinery sector. Because that analysis included LoTOx™ with WGS, water use and wastewater generation were also listed as contributing to CO2eq increases.

Table 4.2-65a
Overall Unmitigated CO2eq Increases Due to Construction and Operation Activities per Refinery Facility (metric tons/year)[1] as analyzed in the December 2015 Final PEA for NOx RECLAIM

Refinery Facility ID	**Temporary Construction Activities (diesel and gasoline fuel use)[2]** (MT/yr)	**Operational Electricity Use[3]** (MT/yr)	**Operational Water Use/ Conveyance** (MT/yr)	**Operational Wastewater Generation** (MT/yr)	**Operational Truck Trips (diesel fuel use)** (MT/yr)	**Total CO2eq** (MT/yr)
1	313	7,522	94	19	26	7,974
2	82	2,116	55	23	12	2,288
3	31	296	0	0	2	329
4	97	4,582	66	30	14	4,789
5	363	4,504	295	133	37	5,332
6	181	3,984	148	66	35	4,414
7	85	1,487	0	0	16	1,588
8	85	2,605	94	19	19	2,822
9	136	3,723	59	30	32	3,980
TOTAL	**1,373**	**30,818**	**813**	**319**	**194**	**33,517**

Source: See Table 4.2-24 of the December 2015 Final PEA for NOx RECLAIM.
[1] 1 metric ton = 2,205 pounds
[2] GHGs from temporary construction activities are amortized over 30 years.
[3] The operational electricity use calculation applied a utility intensity emission factor of 1,110 lb CO2eq/MWh when the utility provider is not identified.

Table 4.2-65b presents the same GHG emission estimates from Table 4.2-65a for temporary construction activities, operational water use/conveyance, operational wastewater generation, and operational truck trips, but with operational electricity use tailored for each facility's utility provider (e.g., LADWP or SCE).

Table 4.2-65b
Overall Unmitigated CO2eq Increases Due to Construction and Operation Activities per Refinery Facility (metric tons/year)[1] as analyzed in the December 2015 Final PEA for NOx RECLAIM with Updated Utility Intensity Emission Factors for Operational Electricity Use

Refinery Facility ID	Temporary Construction Activities (diesel and gasoline fuel use)[2] (MT/yr)	Operational Electricity Use[3] (MT/yr)	Operational Water Use/ Conveyance (MT/yr)	Operational Wastewater Generation (MT/yr)	Operational Truck Trips (diesel fuel use) (MT/yr)	Total CO2eq (MT/yr)
1	313	2,687	94	19	26	3,139
2	82	756	55	23	12	928
3	31	106	0	0	2	139
4	97	2,890	66	30	14	3,097
5	363	1,609	295	133	37	2,437
6	181	1,423	148	66	35	1,853
7	85	939	0	0	16	1,040
8	85	931	94	19	19	1,148
9	136	1,330	59	30	32	1,587
TOTAL	**1,373**	**12,672**	**813**	**319**	**194**	**15,371**

Source: See Table 4.2-24 of the December 2015 Final PEA for NOx RECLAIM.

[1] 1 metric ton = 2,205 pounds

[2] GHGs from temporary construction activities are amortized over 30 years.

[3] The calculations for operational electricity use have been updated for each facility's electricity provider which is either LADWP with a utility intensity emission factor of 694 lb/MWh of CO2eq for reporting year 2021 or SCE with a utility intensity emission factor of 393 lb/MWh of CO2eq for reporting year 2021.

Even after updating the utility intensity emission factors, the project analyzed in the December 2015 Final PEA for NOx RECLAIM would continue to have significant GHG emission impacts. Further, when combining the GHGs from the proposed project as presented in Table 4.2-64b (2,051 MT/yr) with the updated GHGs as presented in Table 4.2-65b (15,371 MT/yr) for the December 2015 Final PEA for NOx RECLAIM, the total GHG emissions would be 17,422 MT/yr, which is greater than the South Coast AQMD air quality significance threshold for GHGs of 10,000 MT/yr but overall much less than the original GHG estimates in the December 2015 Final PEA for NOx RECLAIM of 33,517MT/yr as presented in Table 4.2-65a. The overall effect of the GHG impacts from the proposed project combined with the adjusted GHG analysis in the December 2015 Final PEA for NOx RECLAIM is that the GHG impacts are less severe than the original GHG analysis in the December 2015 Final PEA for NOx RECLAIM, but remain significant.

As part of certifying the December 2015 Final PEA for NOx RECLAIM, the South Coast AQMD Governing Board adopted a mitigation monitoring plan which included mitigation measures specific to GHG impacts.[12] Specifically, the GHG analysis in the December 2015 Final PEA for NOx RECLAIM concluded that there will be a significant increase in GHG emissions from on- and off-road mobile sources during construction and operation, as well as electricity for operating

[12] South Coast AQMD, Attachment 1 to the Governing Board Resolution for the Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), Findings, Statement of Overriding Considerations and Mitigation Monitoring Plan. December 2015. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2015/regxxfindings.pdf

the air pollution control equipment and electricity for pumping and conveying water and wastewater. Therefore, feasible GHG mitigation measures were required, and the following GHG mitigation measures were adopted, and these mitigation measures will continue to apply to the proposed project analyzed in this SEA:

GHG-1 When NOx control equipment is installed and water is required for its operation, the facility operator is required to use recycled water, if available, to satisfy the water demand for the NOx control equipment.

GHG-2 In the event that recycled water cannot be delivered to the affected facility, the facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be supplied to the project.

For context, mitigation measures GHG-1 and GHG-2 were crafted to reduce GHG emissions from water conveyance specific to air pollution control equipment that require water for its operation (e.g., LoTOx™ with a WGS).

For each of the affected facilities whose operators chose to install NOx control equipment pursuant to the December 2015 amendments to the NOx RECLAIM program, the GHG mitigation measures were applied. Similarly, at the time when each facility-specific project is proposed in response to the requirements in PR 1109.1 which are evaluated in this SEA, South Coast AQMD staff will conduct a CEQA evaluation of the facility-specific project and determine if the project is either covered by the analysis in this SEA or the previous analysis in the December 2015 Final PEA for NOx RECLAIM. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing South Coast AQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by South Coast AQMD personnel.

While the currently proposed project may involve the installation and operation of LoTOx™ with a WGS, which requires water in order to function, the majority of the air pollution control devices that may be installed as a result of implementing PR 1109.1 do not require water. As such, these GHG mitigation measures have limited application to the currently proposed project evaluated in this SEA.

Table 4.2-66a
Overall Mitigated CO2eq Increases Due to Construction and Operation Activities per Refinery Facility (metric tons/year)[1] as analyzed in the December 2015 Final PEA for NOx RECLAIM

Refinery Facility ID	**Temporary Construction Activities (diesel and gasoline fuel use)[2]** (MT/yr)	**Operational Electricity Use** (MT/yr) [23]	**Operational Water Use/ Conveyance** (MT/yr)	**Operational Wastewater Generation** (MT/yr)	**Operational Truck Trips (diesel fuel use)** (MT/yr)	**Total CO2eq** (MT/yr)
1	313	7,522	9	2	26	7,872
2	82	2,116	55	23	12	2,288
3	31	296	0	0	2	329
4	97	4,582	66	30	14	4,789
5	363	4,504	28	13	37	4,945
6	181	3,984	14	6	35	4,220
7	85	1,487	0	0	16	1,588
8	85	2,605	94	19	19	2,822
9	136	3,723	59	30	32	3,980
TOTAL	**1,373**	**30,818**	**326**	**121**	**194**	**32,832**

Source: See Table 4.2-25 of the December 2015 Final PEA for NOx RECLAIM.
[1] 1 metric ton = 2,205 pounds
[2] GHGs from temporary construction activities are amortized over 30 years.
[3] The operational electricity use calculation applied a utility intensity emission factor of 1,110 lb CO2eq/MWh when the utility provider is not identified.

Table 4.2-66b presents the same mitigated GHG emission estimates from Table 4.2-66a for temporary construction activities, operational water use/conveyance, operational wastewater generation, and operational truck trips, but with operational electricity use tailored for each facility's utility provider (e.g., LADWP or SCE).

Table 4.2-66b
Overall Mitigated CO2eq Increases Due to Construction and Operation Activities per Refinery Facility (metric tons/year)[1] as analyzed in the December 2015 Final PEA for NOx RECLAIM with Updated Utility Intensity Emission Factors for Operational Electricity Use

Refinery Facility ID	**Temporary Construction Activities (diesel and gasoline fuel use)[2]** (MT/yr)	**Operational Electricity Use** (MT/yr) [3]	**Operational Water Use/ Conveyance** (MT/yr)	**Operational Wastewater Generation** (MT/yr)	**Operational Truck Trips (diesel fuel use)** (MT/yr)	**Total CO2eq** (MT/yr)
1	313	2,687	9	2	26	3,037
2	82	756	55	23	12	928
3	31	106	0	0	2	139
4	97	2,890	66	30	14	3,097
5	363	1,609	28	13	37	2,050
6	181	1,423	14	6	35	1,659
7	85	939	0	0	16	1,040
8	85	931	94	19	19	1,148
9	136	1,330	59	30	32	1,587
TOTAL	**1,373**	**12,672**	**326**	**121**	**194**	**14,686**

Source: See Table 4.2-25 of the December 2015 Final PEA for NOx RECLAIM.
[1] 1 metric ton = 2,205 pounds
[2] GHGs from temporary construction activities are amortized over 30 years.
[3] The calculations for operational electricity use have been updated for each facility's electricity provider which is either LADWP with a utility intensity emission factor of 694 lb/MWh of CO2eq for reporting year 2021 or SCE with a utility intensity emission factor of 393 lb/MWh of CO2eq for reporting year 2021.

None of the affected refinery facilities individually exceeded the GHG industrial significance threshold of 10,000 MT/yr before or after mitigation. However, the GHG emissions from the December 2015 Final PEA for NOx RECLAIM project as a whole exceed, even after adjusting the operational electricity estimates according to each facility's electricity provider, the GHG threshold both before and after mitigation. Pursuant to CEQA Guidelines Section 15130(a), the SEA shall discuss cumulative impacts of a project when the project's incremental effect is cumulatively considerable. **The proposed project under PR 1109.1 is expected to decrease the severity of the overall GHG emission impacts that were previously examined under the December 2015 Final PEA for NOx RECLAIM, but the total projected increase of GHG emissions exceed the South Coast AQMD air quality significance threshold of 10,000 MT/yr for GHGs . Therefore, the proposed project is considered to have significant and unavoidable adverse GHG impacts.**

CARB manages its AB 32 Cap-and-Trade Program, which is a market-based regulation designed to reduce GHGs from multiple sources by setting a firm limit or cap on GHGs from major emission sources and minimize the compliance costs of achieving AB 32 goals. The GHG emissions under the cap are turned into credits, which are distributed to facilities that participate in CARB's Cap-and-Trade Program. A facility's credits give them permission to release a certain quantity of GHG emissions. A facility with more credits than needed can sell them as offsets, enabling other facilities to buy the right to emit more GHGs. Every year, facilities that participate in the Cap-and-Trade Program turn in allowances and offsets for 30 percent of previous year's GHG emissions.

Also, for each compliance period, facilities that participate in the Cap-and-Trade Program turn in allowances and a limited number of offsets to cover the remainder of emissions in that compliance period. Finally, if the compliance deadline is missed or there is a shortfall, four allowances must be provided for every ton of emissions that was not covered in time.

CARB's threshold for being covered in the Cap-and-Trade Program is annual emissions over 25,000 metric tons (MT) of carbon dioxide equivalent emissions (CO2eq). Once a facility exceeds that threshold, the facility will be covered for at least a compliance period of three years. If the GHG emissions for a covered facility is less than this threshold for a compliance period, the facility is eligible to exit the program.

Nine of the 16 refineries listed in Tables 4.2-64a and Tables 4.2-64b participate in CARB's AB 32 Cap-and-Trade program for GHGs. In addition, both utilities, LADWP and SCE, which provide electricity to the affected facilities, participate in CARB's AB 32 Cap-and-Trade program for GHGs. However, while individual facilities subject to PR 1109.1 may be able to offset their GHG emissions from their combustion equipment through CARB's AB 32 Cap-and-Trade program, the proposed project is seeking to reduce NOx emissions from these combustion sources and does not propose to allow the affected facilities to increase production and in turn increase GHGs emitted. Moreover, the primary source of GHG emissions from the proposed project are from on- and off-road mobile sources during construction and operation and electricity use, and these GHG emissions are not regulated by CARB's Cap-and-Trade Program. That is why the GHG emissions from the proposed project are compared the total to the South Coast AQMD air quality significance threshold for GHGs of 10,000 MT/yr CO2eq, and not CARB's significance threshold 10,000 MT/yr CO2eq, to determine whether a significant adverse GHG impact would occur.

None of the affected refinery facilities individually exceed the GHG industrial significance threshold of 10,000 MT/yr before or after mitigation. However, the GHG emissions from the NOx RECLAIM and PR 1109.1 projects as a whole exceed the GHG threshold both before and after mitigation. Therefore, the proposed project is considered to have adverse significant GHG impacts after mitigation. Because the proposed project is expected to generate construction-related CO2eq emissions, and the operational phase of the proposed project is also expected to generate additional GHG emissions, **cumulative GHG adverse impacts after mitigation from the proposed project are considered significant.**

While there may be additional measures that could be imposed upon sources with potential increases in GHG emissions, CARB is already adopting measures pursuant to AB 32 that require the maximum technically feasible and cost-effective GHG emission reductions from industry categories such as refineries. The state achieved its 2020 GHG emissions reductions target of returning to 1990 levels four years earlier than mandated by AB 32, and is now implementing strategies in its 2017 Scoping Plan Update to further reduce GHG emissions by 40% below 1990 levels by 2030. CEQA Guidelines Section 15364 defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time…" All CARB GHG measures are required to meet the "maximum feasible and cost-effective" reductions test. This test is equally as stringent as the CEQA definition of "feasible." Given that CARB has been working on this statutory mandate for several years, and has an entire office and staff devoted to GHG rulemaking, it would not be feasible for South Coast AQMD staff to develop generally applicable GHG reduction measures that go beyond CARB measures. Thus, application of CARB rules will require the maximum feasible GHG reductions for existing sources.

U.S. EPA has stated that because there is no national ambient air quality standard for CO2, or any of the other primary GHGs, and U.S. EPA does not plan to promulgate any, the "nonattainment" New Source Review program that applies to criteria pollutants will not apply to GHGs[13]. However, for a New Source Review program that applies to attainment pollutants, prevention of significant deterioration (PSD) will also apply. PSD applies to any "major stationary source" of pollutants subject to regulation under the federal CAA. Accordingly, because EPA has promulgated its GHG reduction rules for motor vehicles, GHGs is a pollutant that is subject to regulation under the federal Clean Air Act. U.S. EPA has issued its interpretation that GHGs become regulated pollutants as of the time the motor vehicle rule becomes effective (i.e., January 2011). South Coast AQMD concluded at the time that it would not be feasible to begin requiring GHG BACT prior to January 2011, because it would be necessary to amend the South Coast AQMD's rules in order to do so.

U.S. EPA promulgated its GHG PSD rule requiring several "steps." In Step 1, which began on January 2, 2011, only facilities that would already be subject to Title V or PSD would be subject to GHG requirements under these programs. In addition, a facility modification would only trigger PSD for GHGs if the modification resulted in an increase of 75,000 MT/yr CO2eq. Therefore, South Coast AQMD began requiring GHG BACT for sources already subject to PSD and having a GHG increase of 75,000 MT/yr or more, effective January 2, 2011. Recently, the U.S. Supreme Court held that U.S. EPA was limited to Step 1.

At the local level, South Coast AQMD Rule 1714 – Prevention of Significant Deterioration for Greenhouse Gases, implements PSD requirements for GHGs. South Coast AQMD interprets its Rule 1714 to be consistent with the U.S. Supreme Court decision.

Although the definition of federal BACT for PSD sources is somewhat different from the definition of BACT that South Coast AQMD uses for nonattainment New Source Review, this definition is still at least as stringent as the CEQA definition of feasible. Pursuant to federal CAA Section 169(3) [42 U.S.C. Section 7479(3)], the term "best available control technology" means in pertinent part "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant." Therefore, GHG BACT is at least as stringent as CEQA's definition of feasible mitigation, which similarly allows consideration of economic, technological and environmental factors. Thus, application of BACT will require the maximum feasible reductions of GHGs at new or modified sources, which would otherwise be subject to PSD. Because the potential GHG increases at each affected facility are individually well below U.S. EPA's initial thresholds, GHG BACT would not be required for any of the individual facilities making facility modifications to comply with the proposed project.

Further, in light of the uncertainty associated with the effects of the proposed project on individual facilities whose operators have not submitted any applications for permits to construct as a result of the proposed project, the adoption and implementation of feasible mitigation beyond the

[13] "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Proposed Rule" ("Tailoring Rule Proposal") 74 FR 55292, 55297 (October 27, 2009).

requirement of using recycled water when available will not feasibly reduce significant air quality and climate change impacts to a less-than-significant level, because it would not be feasible for the South Coast AQMD to attempt to develop and impose additional GHG mitigation measures for the myriad of source categories that may be affected by the proposed project. Accordingly, the project-level and cumulative impacts identified as significant in this chapter cannot feasibly be mitigated to a less-than-significant level and remain significant and unavoidable.

SUBCHAPTER 4.3

HAZARDS AND HAZARDOUS MATERIALS

4.3 HAZARDS AND HAZARDOUS MATERIALS

PR 1109.1 proposes to reduce NOx emissions from refinery equipment and transition equipment that is currently permitted under the NOx RECLAIM program to a command-and-control regulatory structure by requiring affected equipment operating at RECLAIM or former RECLAIM facilities to comply with current BARCT.

This chapter independently considers the currently proposed project and analyzes the incremental changes, if any, relative to the baseline established in the December 2015 Final PEA for NOx RECLAIM. The December 2015 Final PEA for NOx RECLAIM previously analyzed hazards and hazardous materials impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS at 20 facilities, with nine from the refinery sector and 11 from the non-refinery sector . The NOP/IS for the Draft PEA for NOx RECLAIM identified the environmental topic of hazards and hazardous materials impacts as having potentially significant adverse impacts which were further analyzed in the December 2015 Final PEA for NOx RECLAIM and concluded that significant adverse impacts to hazards and hazardous materials due to ammonia would occur.

Seven additional facilities and additional equipment categories will apply to the proposed project when compared to the project analyzed in December 2015 Final PEA for NOx RECLAIM for 20 facilities, with nine from the refinery-sector. However, the same types of air pollution control equipment with similar impacts to the same environmental topic areas that were previously analyzed are expected to occur with the proposed project except that the proposed project will have an incremental increase in the number of new SCRs installed with the associated ammonia storage tanks and the number of existing SCRs upgraded. The proposed project is also expected to involve the replacement of existing burners with ULNBs and these activities were not previously analyzed in the December 2015 Final PEA for NOx RECLAIM. However, ULNBs do not use ammonia or any other hazardous material. Thus, this SEA updates the previous hazards and hazardous materials impacts analysis conducted in the December 2015 Final PEA for NOx RECLAIM to reflect these changes.

The potential for hazards exists in the production, use, storage, and transportation of hazardous materials. For the purposes of this SEA, the term "hazardous materials" refers to both hazardous materials and hazardous wastes. In general, hazards can occur due to natural events, such as earthquake, and non-natural events, such as mechanical failure or human error. The risk associated with each affected facility is defined by the probability of an event and the consequence (or hazards) should the event occur.

Hazardous materials may be found at industrial production and processing facilities. Some facilities produce hazardous materials as their end product, while others use such materials as an input to their production process. Hazardous materials are stored at facilities that produce such materials and at facilities where hazardous materials are a part of the production process. Specifically, storage refers to the bulk handling of hazardous materials before and after they are transported to the general geographical area of use. Currently, hazardous materials are transported throughout the South Coast AQMD jurisdiction by various modes including rail, highway, water, air, and pipeline. Hazard concerns are related to the potential for fires, explosions or the release of hazardous materials and substances in the event of an accident or upset conditions.

4.3.0 Introduction

As previously summarized in Table 4.1-1, various BARCT control technology options are available for each category of combustion equipment. The baseline for this SEA is from the December 2015 Final PEA for NOx RECLAIM which specifically evaluated hazard impacts from new or modified add-on air pollution control equipment that use hazardous materials such as: 1) SCRs using ammonia and catalysts; and 2) scrubbers such as LoTOx™ with and without WGSs using caustic (sodium hydroxide and soda ash) and UltraCat™ with DGS technology using ammonia and hydrated lime.

The proposed project applies to 16 facilities and nine of these facilities were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Even though more facilities and more combustion equipment categories will be affected by the proposed project, the key differences between the analysis in the the December 2015 Final PEA for NOx RECLAIM and this SEA for the proposed project is that this SEA will need to update the previous CEQA analysis relative to hazards and hazardous materials to: 1) increase the number of existing SCRs which are expected to undergo an upgrade which means additional units undergoing catalyst replacement but without increases the amount of existing ammonia use; and 2) adjust the quantity of new SCRs that will be installed and the projected use of ammonia needed to operate the new SCRS.

While the proposed project also indicates that LoTOx™ with and without WGSs using caustic such as sodium hydroxide and soda ash and UltraCat™ with DGS technology using ammonia and hydrated lime may be installed for some categories of combustion equipment, these air pollution control devices and the associated chemicals were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Moreover, the proposed project neither contains any changes to the type of combustion equipment that would be expected to utilize these scrubbers nor requires any updates to the chemicals that will be needed. Thus, an updated hazards and hazardous materials analysis of scrubber-related impacts will not be required for this SEA.

Finally, while the potential for replacing existing burners with ULNBs in some combustion equipment and the associated environmental impacts were not previously analyzed in the December 2015 Final PEA for NOx RECLAIM, a new hazards and hazardous materials analysis of ULNB-related impacts will also not be required for this SEA since ULNBs do not utilize any hazardous materials for their operation.

The hazards and hazardous materials analysis in this SEA focuses on the changes in use, transport, storage, and handling of hazardous materials as a result of installing new SCRs or upgrading existing SCRs as part of implementing the proposed project when compared to the previous hazards and hazardous materials impact analysis included in the December 2015 Final PEA for NOx RECLAIM. In addition to tiering off the two previous CEQA documents, this SEA follows the same approach in the hazards and hazardous materials impacts analyses specific to the use of SCRs and ammonia which were conducted in CEQA documents previously for the following other NOx RECLAIM landing rules:

- Final Subsequent Environmental Assessment for Proposed Amended Rule 1110.2 – Emissions from Gaseous-and Liquid-Fueled Engines and Proposed Amended Rule 1100 – Implementation Schedule for NOx Facilities, certified November 1, 2019.

(Available at: http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2019/par-1110-2_final-sea_with-appx.pdf)

- Final Subsequent Environmental Assessment for Proposed Amended Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines, Certified January 4, 2019. (Available at: http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2019/par-1134---final-sea_with_appdx.pdf)
- Final Subsequent Environmental Assessment for Proposed Amended Rules 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters; 1146.1 – Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters; 1146.2 - Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters; and Proposed Rule 1100 – Implementation Schedule for NOx Facilities, certified December 7, 2018.
(Available at: http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2018/pars-1146-series---final-sea---full-merge-113018.pdf)
- Final Mitigated Subsequent Environmental Assessment for Proposed Amended Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities, certified November 2, 2018.
(Available at: http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2018/par-1135---final-mitigated-sea_with-appendices.pdf)

To the extent that future projects as part of compliance with PR 1109.1 use, transport, or dispose of hazardous materials conform to the hazards and hazardous materials analysis in this SEA, no further hazards analysis may be necessary. If site-specific characteristics are involved with future projects for compliance with PR 1109.1 are outside the scope of this analysis, further hazards analysis may be warranted.

4.3.1 Significance Criteria

Impacts associated with hazards will be considered significant if any of the following occur:

- Non-compliance with any applicable design code or regulation.
- Non-conformance to National Fire Protection Association standards.
- Non-conformance to regulations or generally accepted industry practices related to operating policy and procedures concerning the design, construction, security, leak detection, spill containment or fire protection.
- Exposure to hazardous chemicals in concentrations equal to or greater than the Emergency Response Planning Guideline (ERPG) 2 levels.

4.3.2 Potential Hazards and Hazardous Materials Impacts and Mitigation Measures

The key effects of implementing the proposed project and the determination of which aspects involve hazards and hazardous materials focus on: 1) the anticipated increase of substances used to operate the new or modified NOx controls; and, 2) the increased capture of hazardous substances as part of the overall NOx reduction effort.

Table 4.3-1 summarizes the estimated number of NOx emission control devices that were not previously analyzed the December 2015 Final PEA for NOx RECLAIM but will be analyzed in this SEA because they may be installed as part of implementing PR 1109.1. Of the NOx air pollution control devices listed in Table 4.3-1, only the SCRs utilize ammonia and and catalyst[14], of which only ammonia is a hazardous material. ULNB technology does not use any substance, hazardous or otherwise, for its operation. As such, the use of ammonia is the focus of the hazards and hazardous materials impacts analysis in this SEA.

Table 4.3-1

Estimated Number of NOx Air Pollution Control Devices Per Equipment Category for 16 Refineries subject to PR 1109.1 Not Previously Analyzed Under NOx RECLAIM

Equipment Category	Number of Affected Facilities	Estimated Number of Air Pollution Control Devices Not Previously Analyzed in the December 2015 Final PEA for NOx RECLAIM
Refinery Process Heaters and Boilers	9	~~59~~ 47 Burner Replacements with ULNBs ~~20~~ 25 New SCRs ~~6~~ 3 SCR Upgrades 9 Heater/Boiler Replacements
SRU/TGs	4	5 Burner Replacements with ULNBs
Thermal Oxidizers	4	8 Burner Replacements with ULNBs
Refinery Gas Turbines	1	1 SCR Upgrade
	TOTAL	**~~20~~ 25 New SCRs** **~~7~~ 4 SCR Upgrades** **~~72~~ 60 Burner Replacements with ULNBs** **9 Heater/Boiler Replacements**

4.3.2.1 Hazard Safety Regulations

Notwithstanding implementation of PR 1109.1, operators of each affected facility must comply or continue to comply with various regulations, including Occupational Safety and Health Administration (OSHA) regulations (29 Code of Federal Regulations (CFR) Part 1910) that require the preparation of a fire prevention plan, and 20 CFR Part 1910 and CCR Title 8 that require prevention programs to protect workers who handle toxic, flammable, reactive, or explosive materials. In addition, Section 112 (r) of the CAA Amendments of 1990 [42 United States Code (USC) 7401 et. seq.] and Article 2, Chapter 6.95 of the California HSC require facilities that handle listed regulated substances to develop Risk Management Programs (RMPs) to prevent accidental releases of these substances. If any of the affected facilities has already prepared an RMP, it may need to be revised to incorporate any changes that may be associated with the proposed project. The Hazardous Materials Transportation Act is the federal legislation that regulates transportation of hazardous materials.

A number of physical or chemical properties may cause a substance to be hazardous. With respect to determining whether a material is hazardous, the Safety Data Sheet (SDS) for each specific

[14] An overview of selective catalytic reduction post-combustion control equipment including the types of catalysts used by SCR systems is included in this SEA in Chapter 2 – Project Description, Section 2.6.2 NOx Control Technologies.

material should be consulted for the National Fire Protection Association (NFPA) 704 hazard rating system (i.e. NFPA 704). NFPA 704 is a “standard (that) provides a simple, readily recognized, easily understood system for identifying the specific hazards of a material and the severity of the hazard that would occur during an emergency response. The system addresses the health, flammability, instability, and special hazards presented from short-term, acute exposures that could occur as a result of a fire, spill, or similar emergency[15].” In addition, the hazard ratings per NFPA 704 are used by emergency personnel to quickly and easily identify the risks posed by nearby hazardous materials in order to help determine what, if any, specialty equipment should be used, procedures followed, or precautions taken during the first moments of an emergency response. The scale is divided into four color-coded categories, with blue indicating level of health hazard, red indicating the flammability hazard, yellow indicating the chemical reactivity, and white containing special codes for unique hazards such as corrosivity and radioactivity. Each hazard category is rated on a scale from 0 (no hazard; normal substance) to 4 (extreme risk). Table 4.3-2 summarizes what the codes mean for each hazards category.

[15] National Fire Protection Association, FAQ for Standard 704. https://www.nfpa.org/assets/files/aboutthecodes/704/704_faqs.pdf

Table 4.3-2
NFPA 704 Hazards Rating Codes

Hazard Rating Code	**Health (Blue)**	**Flammability (Red)**	**Reactivity (Yellow)**	**Special (White)**
4 = Extreme	Very short exposure could cause death or major residual injury (extreme hazard)	Will rapidly or completely vaporize at normal atmospheric pressure and temperature, or is readily dispersed in air and will burn readily. Flash point below 73°F.	Readily capable of detonation or explosive decomposition at normal temperatures and pressures.	**~~W~~** = Reacts with water in an unusual or dangerous manner.
3 = High	Short exposure could cause serious temporary or moderate residual injury	Liquids and solids that can be ignited under almost all ambient temperature conditions. Flash point between 73°F and 100°F.	Capable of detonation or explosive decomposition but requires a strong initiating source, must be heated under confinement before initiation, reacts explosively with water, or will detonate if severely shocked.	**OXY** = Oxidizer
2 = Moderate	Intense or continued but not chronic exposure could cause temporary incapacitation or possible residual injury.	Must be moderately heated or exposed to relatively high ambient temperature before ignition can occur. Flash point between 100°F and 200°F.	Undergoes violent chemical change at elevated temperatures and pressures, reacts violently with water, or may form explosive mixtures with water.	**SA** = Simple asphyxiant gas (includes nitrogen, helium, neon, argon, krypton and xenon).
1 = Slight	Exposure would cause irritation with only minor residual injury.	Must be heated before ignition can occur. Flash point over 200°F.	Normally stable, but can become unstable at elevated temperatures and pressures	
0 = Insignificant	Poses no health hazard, no precautions necessary	Will not burn	Normally stable, even under fire exposure conditions, and is not reactive with water.	

Operators of affected facilities will be required to comply with all applicable design codes and regulations, conform to NFPA standards, and conform to policies and procedures concerning leak detection containment and fire protection. However, even with implementation of the applicable safety regulations, significant adverse offsite hazards impacts are expected as explained later in this chapter (see Hazards Associated with an Ammonia Tank Rupture Scenario).

4.3.2.2 Hazard Impacts on Water Quality

A spill of any hazardous material, such as aqueous ammonia, that is used and stored at any of the affected facilities could occur under upset conditions such as an earthquake, tank rupture, or tank overflow. Spills could also occur from corrosion of containers, piping and process equipment, and leaks from seals or gaskets at pumps and flanges. A major earthquake would be a potential cause of a large spill. Other causes could include human or mechanical error. Construction of the vessels and foundations in accordance with the Uniform Building Code Zone 4 requirements helps structures to resist major earthquakes without collapse but may result in some structural and non-structural damage following a major earthquake. Any facility with storage tanks on-site is currently required to have emergency spill containment equipment and would implement spill control measures in the event of an earthquake or power failure. Storage tanks typically have secondary containment such as a berm which would be capable of holding up to 110 percent of the tank contents. Should a rupture occur, the spilled contents collected in the berm would be drained gravimetrically to an enclosed collection system.

While spills at the affected facilities would generally be captured within containment areas, large spills occurring outside of containment areas at the affected facilities are expected to be captured by the process water system where the spilled material would be collected, and treated. Because of the containment system design, spills are not expected to migrate offsite and as such, potential adverse water quality hazard impacts are considered to be less than significant.

4.3.2.3 Project Specific Impacts

The following discussion describes the hazards profile for each substance involved with implementing the proposed project (e.g., ammonia and catalyst needed for operating SCRs).

Hazards Associated with the Routine Transport, Use, and Storage of Ammonia

Ammonia (NH3) though not a carcinogen, is a chronic and acutely hazardous material. Located on the SDS for NH3 (19 percent by weight), the hazards ratings are as follows: health is rated 3 (highly hazardous), flammability is rated 1 (slight) and reactivity is rated 0 (none). Therefore, an increase in the use of ammonia in response to the installation of new SCRs as part of implementing PR 1109.1 may increase the current existing risk setting associated with deliveries (i.e., truck and road accidents) and onsite or offsite spills for each of the facilities that currently use or will begin to use ammonia. Exposure to a toxic gas cloud is the potential hazard associated with this type of control equipment. A toxic gas cloud is the release of a volatile chemical such as anhydrous ammonia that could form a cloud and migrate off-site, thus exposing individuals. Anhydrous ammonia is heavier than air such that when released into the atmosphere, would form a cloud at ground level rather than be dispersed “Worst-case” conditions tend to arise when very low wind speeds coincide with the accidental release, which can allow the chemicals to accumulate rather than disperse.

For any new construction of air pollution control equipment that utilizes ammonia, such as SCR technology, current South Coast AQMD policy does not allow the use of ~~anhydrous~~ ammonia at concentrations greater than 19% for new construction of a storage tank if the quantity capable of being stored is greater than 500 pounds or if the quantity is less than 500 pounds but there is a risk for an offsite consequence in the event of a tank failure. Existing storage tanks containing ammonia at concentrations greater than 19% may be used to service new installations of air pollution control equipment. To minimize the hazards associated with the use of ammonia, aqueous ammonia at a concentration of no more than 19 percent by weight (19% aqueous ammonia) is typically required as a permit condition associated with the installation of new SCR equipment. This policy is why the December 2015 Final PEA for NOx RECLAIM assumed that all ammonia utilized for new SCRs (as well as UltraCat™ DGSs), would be 19% aqueous ammonia. Moreover, for the analysis in this SEA, in accordance with South Coast AQMD policy, the new SCRs are assumed to utilize 19% aqueous ammonia. However, for any existing SCR which may undergo an upgrade would be expected to continue to utilize the same type of ammonia (e.g., anhydrous, 19% aqueous ammonia or some other concentration) and about the same quantity as it is currently using. An SCR upgrade consists of catalyst replacement and modification of the ammonia injection grid; the existing ammonia storage tank for SCR upgrades will not require any physical modifications. The analysis also assumes that the existing ammonia storage tank for SCR upgrades will continue to provide the ammonia needed to continue operating the existing SCRs, without requiring any physical modifications. Depending on the number of additional SCRs that would need to receive ammonia from an existing ammonia storage tank, the ammonia throughput limit on the permit may need to be revised. Increases of ammonia throughput for an existing tank would not be expected to change the existing risk associated with an offsite consequence in the event of a tank rupture.

The ammonia analysis in the December 2015 Final PEA for NOx RECLAIM assumed that each new SCR installation would also involve the installation of one new 11,000-gallon ammonia tank of 19% aqueous ammonia. Thus, all of the ammonia delivered to each facility for new SCRs would be 19% aqueous ammonia, which in turn, helped estimate the number of vehicle trips associated with ammonia deliveries. If a higher concentration of ammonia is currently being delivered to a facility for an existing ammonia storage tank that is intended to provide ammonia to new SCRs installed as part of the proposed project, the number of vehicle trips associated with higher concentrations of ammonia will be fewer than for those delivering 19% aqueous ammonia because less water is contained in the ammonia (e.g., 19% aqueous ammonia contains 81% water, 29% ammonia contains 71% water, and anhydrous ammonia contains no water).

The analysis in the December 2015 Final PEA for NOx RECLAIM assumed that ammonia would be delivered via 7,000-gallon trucks and this SEA applies this same assumption in the updated analysis for the new SCRs that would be installed if the proposed project is implemented.

In addition, the routine transport, transfer, storage and use, of ammonia inherently poses a certain risk of a release to the environment. Thus, the routine transport, transfer, storage and use of ammonia may increase as a result of implementing PR 1109.1. Further, compliance with PR 1109.1 may alter the transportation modes for ammonia to and from the existing facilities.

The analysis of hazard impacts can rely on information from past similar projects (i.e., installing new, or retrofitting existing equipment with NOx control technology that utilizes ammonia to comply with South Coast AQMD rules and regulations and installation of associated ammonia storage tanks) where the South Coast AQMD was the lead agency responsible for preparing an environmental analysis pursuant to CEQA. To the extent that future projects install NOx control technology that utilizes ammonia and associated ammonia storage equipment conform to the ammonia hazard analysis in this SEA, no further hazard analysis may be necessary. If a future project, as part of compliance with PR 1109.1, involves site-specific installation of NOx control equipment and that equipment utilizes ammonia to the extent that such installation or use is outside the scope of this analysis, an additional ammonia hazards analysis may be warranted.

If the proposed project is implemented such that ~~20~~ 25 new SCRs are installed, approximately ~~four~~ five tons per day (equivalent to approximately ~~1,140~~ 1,288 gallons per day) of aqueous ammonia (at 19 percent concentration) would be needed to operate the equipment. For comparison, the amount of ammonia projected to be needed in the December 2015 Final PEA for NOx RECLAIM analysis was approximately 39.5 tons per day or 10,284 gallons per day to supply approximately 117 new SCRs (see December 2015 Final PEA for NOx RECLAIM, Subchapter 4.4 – Hazards and Hazardous Materials, pp. 4.4-10 through 4.4-11). The December 2015 Final PEA for NOx RECLAIM assumed that the affected facilities will receive ammonia deliveries by tanker trucks via public roads from a local ammonia supplier located in the greater Los Angeles area and this SEA relies on the same assumption. Since one ammonia delivery truck can deliver up to 7,000 gallons per visit, based on the peak daily total volume of ammonia that would be needed to satisfy the ammonia demand associated with the proposed project, seven additional ammonia delivery trucks would be needed on a peak day for the proposed project. For comparison, the December 2015 Final PEA for NOx RECLAIM analysis estimated that 28 ammonia delivery trucks would be needed on a peak day.

To not underestimate impacts, the December 2015 Final PEA for NOx RECLAIM analysis contained a conservative assumption that all new ammonia storage tanks that were projected to be installed for the refinery sector would be the maximum capacity of 11,000 gallons which is based on combustion equipment with the largest heat rating. This SEA relies on the same assumption. However, as a practical matter, the estimates of ammonia that may be needed to achieve NOx reductions were calculated based on the individual heat ratings of all the affected combustion equipment. Thus, for the smallest combustion units, the actual size of the aqueous ammonia storage tank that may be needed could be much smaller, at 600 gallons. Because the capacity of the ammonia tanks may range between 600 gallons to 11,000 gallons, the actual amount of ammonia needed on a daily basis per facility will also vary, and the actual amount of aqueous ammonia delivered per facility on a peak day will vary. The onsite storage capacity and the projections for future ammonia use and storage are estimated in the "Operational Totals" sheet of the "Summary of Operational Emissions" excel file in Appendix C.

The accidental release of ammonia from a delivery and use is a localized event (i.e., the release of ammonia would only affect the receptors that are within the zone of the toxic endpoint). The accidental release from a delivery would also be temporally limited because deliveries are not likely to be made at the same time in the same area. Based on these limitations, it is assumed that an accidental release would be limited to a single delivery or single facility at a time. In addition, it is unlikely that an accidental release from both a delivery truck and the stationary storage tank would result in more than the amount evaluated in the catastrophic release of the storage tank because the level of ammonia in the storage tanks would be low or else the delivery trip would not be necessary.

Further, the hazards associated with a transportation release scenario during ammonia delivery is much greater than an alternative release scenario of an ammonia leak at a facility when a truck is offloading ammonia into a facility's storage tank because a transportation release could occur on roadways with no containment and a higher potential to create an offsite risk. Similarly, the worst-case scenario of a catastrophic failure of an ammonia tank at a facility would exhibit greater impacts than when a truck is offloading ammonia into a facility's storage tank. Fewer impacts are associated with the alternative release scenario of an ammonia leak at a facility when a truck is offloading ammonia into a facility's storage tank because the hole where a leak or spill would occur would result in a smaller volume of a spill on a pounds per minute basis which would result in a shorter toxic endpoint distance (with lessened potential to create an offsite risk) than for catastrophic failure of an ammonia storage tank itself which could contain a larger volume of ammonia than a delivery truck filled at maximum capacity.

A hazard analysis is dependent on knowing the exact location of the spill (e.g., meteorological conditions, location of the receptor, et cetera,). A site-specific hazard analysis is difficult to conduct without this information. However, in absence of this detailed information, an offsite consequence analysis using the U.S. EPA's RMP*Comp model[16] can be performed to estimate a toxic endpoint distance from the accidental release of aqueous ammonia due to a tank rupture. Although it is South Coast AQMD policy to reduce potential hazards associated with ammonia by requiring a permit condition that limits the aqueous ammonia concentration to 19 percent, the U.S. EPA's RMP*Comp model only has the capability of evaluating the hazard potential for 20 percent aqueous ammonia. Therefore, potential adverse impacts from aqueous ammonia when using U.S. EPA's RMP*Comp model would need to be evaluated based on 20 percent aqueous ammonia.

The hazards scenarios associated with the routine transportation, storage, and use of ammonia are discussed in detail below.

Hazards Associated with Routine Transportation of Ammonia Release Scenario:
Installation of new SCRs is expected to increase the use of ammonia due to implementation of PR 1109.1 such that increased quantities of ammonia delivered via tanker trucks on public roads to the affected facilities is expected to occur. Tanker trucks capable of delivering aqueous ammonia have a capacity of 7,000 gallons and are designed to withstand accidents during transportation. However, accidental releases may still occur. One accidental release scenario was identified in the December 2015 Final PEA for NOx RECLAIM as having the potential to generate significant adverse hazard impacts from the accidental release of delivered aqueous ammonia due to a tank rupture during transportation (see the December 2015 Final PEA for NOx RECLAIM, Subchapter 4.4 - Hazards and Hazardous Materials, pp. 4.4-11 through 4.4-12). Based on the worst-case defaults of a delivery truck spill of 7,000 gallons using U.S. EPA's RMP*Comp model, the toxic endpoint distance from the delivery truck would be 0.4 miles. Because sensitive receptors may be within this toxic endpoint distance (toxic endpoint concentration of 0.14 milligrams per liter (mg/L) based on ERPG-2), depending on the location of the spill, the accidental release of ammonia during transport could cause significant adverse hazards impacts. The ammonia transportation analysis in the December 2015 Final PEA for NOx RECLAIM is directly applicable to the currently proposed project since there is a potential for an increase in the transport, storage

[16] EPA RMP*Comp is only a browser-based program that runs in Internet Explorer, Firefox, Chrome, and Safari. https://cdxnodengn.epa.gov/cdx-rmp-maintain/action/rmp-comp

and use of ammonia which may substantially alter existing transportation hazards associated with ammonia. Consequently, increased usage of ammonia due to implementation of PR 1109.1 could generate significant adverse hazard impacts during routine transport as a result of an accidental release of delivered aqueous ammonia.

Hazards Associated with an Ammonia Tank Rupture Scenario:
Installation of new SCRs is expected to increase the amount of ammonia stored and used at the affected facilities due to implementation of PR 1109.1. Facilities that choose to install NOx control devices that use ammonia, such as SCR systems, would need ammonia tanks that range in size from 600 to 11,000 gallons in capacity, with daily usage varying by facility need.

Construction of ammonia tanks id required to comply with all applicable building codes and U.S. EPA's spill prevention control and countermeasure regulations. However, catastrophic failure of a tank may still occur. Two accidental release scenarios were identified in the December 2015 Final PEA for NOx RECLAIM and both scenarios concluded the hazards and hazardous materials impacts due to tank rupture as less than significant (see the December 2015 Final PEA for NOx RECLAIM, Subchapter 4.4 - Hazards and Hazardous Materials, pp. 4.4-12 through 4.4-13).

The ammonia tank rupture scenario as previously analyzed in the December 2015 Final PEA for NOx RECLAIM utilized U.S. EPA's RMP*Comp model and estimated a toxic endpoint distance of 0.1 mile from a ruptured tank (toxic endpoint concentration of 0.14 mg/L based on ERPG-2) spilling up to 12,100 gallons (110 percent of the maximum sized tank of 11,000 gallons) of aqueous ammonia at a 20% concentration. This SEA is relying on this ammonia tank rupture scenario because: 1) the same nine facilities (Facilities 1 through 9) from the refinery-sector that were previously analyzed in the December 2015 Final PEA for NOx RECLAIM, are the same facilities that are subject to the currently proposed project; and 2) of the additional seven facilities (Facilities 10 through 16) that are affected by the proposed project but that were not previously analyzed in the December 2015 Final PEA for NOx RECLAIM, only Facility 10 is identified as potentially needing a new SCR for one of its boilers and in turn a new ammonia tank. Even though a new SCR and new ammonia tank at Facility 10 was not previously analyzed in the December 2015 Final PEA for NOx RECLAIM, representatives of Facility 10 have indicated that they intend to utilize an existing SCR equipped with an existing ammonia tank. For this reason, Facility 10 would not be expected to contribute to a new offsite consequence (since the tank is existing and an offsite consequence risk already exists which is not a direct result of the facility complying with PR 1109.1) associated with a ruptured ammonia storage tank, regardless of the size of the existing tank and its current location, in order to comply with the currently proposed project.

Also, information about site-specific projects to install ammonia tanks as a result of implementing PR 1109.1 is uncertain at this point in time, and it would be speculative to predict or forecast the precise location of new ammonia tanks on a facility-by-facility basis since a hazard analysis is dependent on knowing the exact location of a hazard within a site (e.g., the location of the ammonia storage tank(s)), meteorological conditions, location of the receptor, etc.). Predicting where facilities would locate ammonia tanks without firm evidence based on facts to support the analysis would require an engagement in speculation or conjecture that is inappropriate for this SEA.

Accordingly, the impacts associated with an ammonia tank rupture in this SEA are generally based on the assumption that facilities are often large enough and have sufficient space to site new storage tanks more than 0.1 mile away from the property line so that should a spill occur, the release would not expose off-site sensitive receptors, thus minimizing the potential impacts associated with new ammonia tanks. Further, storage tanks typically have secondary containment such as a dike or berm, which would be capable of containing 110 percent of the contents of the storage tanks. Should a rupture occur, the spilled contents collected in the berm would be drained gravimetrically to an enclosed collection system. While spills at the affected facilities would generally be captured within containment areas, large spills occurring outside of containment areas at the affected facilities are expected to be captured by the process water system where the spilled material would be collected and treated. Because of the containment system design, spills are not expected to migrate offsite.

However, since it is speculative to predict or forecast where individual facilities will choose to site their new ammonia tanks, it is not possible to quantify the exact toxic endpoint that will result from compliance with PR 1109.1 and therefore it is not possible to conclusively determine that all sensitive receptors in proximity of an affected facility would not be located within the toxic endpoint distance. Therefore, this SEA conservatively considers the environmental consequences regarding hazards impacts from a catastrophic rupture of an ammonia tank as potentially significant adverse hazards impact.

Hazards Associated with the Routine Transport, Use, or Disposal of Fresh and Spent Catalyst

As previously analyzed in the December 2015 Final PEA for NOx RECLAIM and as anticipated with the currently proposed project and analyzed in the SEA, installation of new SCRs is expected to require the initial installation of fresh catalyst and then followed by a periodic replacement of spent catalyst with fresh catalyst approximately once every five years per SCR.

Commercial catalysts used in SCR systems are comprised of a ceramic structure with a base material of titanium dioxide (TiO2) that is coated with either tungsten trioxide (WO3), molybdic anhydride (MoO3), vanadium pentoxide (V2O5), or iron oxide (Fe2O3). Catalysts for SCRs are manufactured in pre-formed stable, solid block structures and so there is no potential for a spill or release when delivered as fresh catalyst or hauled away as spent catalyst. SCR catalysts are replaced approximately once every five years.

Spent catalysts are generally not hazardous and can be disposed of in a non-hazardous landfill. The composition and type of the catalyst will determine the type of landfill that would be eligible to handle the disposal. For example, catalysts with a metal structure would be considered a metal waste, like copper pipes, and not a hazardous waste. Therefore, metal structure catalysts would not be a regulated waste requiring disposal in a Class I landfill, unless it is friable or brittle. As ceramic-based catalysts contain a fiber-binding material, they are not considered friable or brittle and, thus, would not be a regulated waste requiring disposal in a Class I landfill. Furthermore, typical catalyst materials are not considered to be water soluble, which also means they would not require disposal in a Class I landfill. In both cases, spent catalyst would not require disposal in a Class I landfill

In lieu of disposal, spent catalyst can be recycled for other uses. Facilities that have existing catalyst-based operations currently arrange for the catalyst blocks to be recycled. For example, local refineries have historically been arranging for their spent catalyst to be hauled to a cement manufacturing plant located outside of the South Coast AQMD jurisdiction. Moreover, due to the heavy metal content and relatively high cost of catalysts, recycling can be more lucrative than disposal. Thus, facilities that have existing SCR units and choose to employ additional SCR equipment as part of implementing the proposed project, in most cases already recycle their spent catalyst and subsequently may continue to do so with any additional catalyst that may be needed.

Several physical or chemical properties may cause a substance to be hazardous, including toxicity (health), flammability, reactivity, and any other specific hazard such as corrosivity or radioactivity. Based on a hazard rating from 0 to 4 (0 = no hazard; 4 = extreme hazard) located on the Safety Data Sheet (SDS) the hazard rating for vanadium pentoxide/tungsten oxide ceramic catalyst, for example, health is rated 1 (slightly hazardous), flammability is rated 1 (slightly flammable) and reactivity is rated 0 (none). The composition of the catalyst used in the SCR units, combined with the metals content of the flue gas will determine the hazard rating and whether the spent catalyst is considered a hazardous material or hazardous waste. This distinction is important because a spent catalyst that qualifies as a hazardous material could be still be recycled (e.g., to be reused by another industry such as manufacturing Portland cement). However, for any spent catalyst that is considered hazardous waste, if it is not recycled, then it must be disposed of in a landfill that can accept hazardous waste.

Based on the aforementioned information, it is likely that spent catalysts would be considered a "designated waste," which is characterized as a non-hazardous waste consisting of, or containing pollutants that, under ambient environmental conditions, could be released at concentrations in excess of applicable water objectives, or which could cause degradation of the waters of the state (California Code of Regulations, Title 23, Chapter 3 Subparagraph 2522(a)(1)). Depending on its actual waste designation, spent catalysts would likely be disposed of in a Class II landfill or a Class III landfill that is fitted with liners.

Therefore, the handling of fresh and spent catalysts are not expected to cause significant adverse hazards and hazardous materials impacts.

Proximity to Schools

Of the facilities that may install new SCRs and in turn, new ammonia storage tanks as a result of implementing the proposed project, three facilities: Facility 5, Facility 7, and Facility 10 are located within one-quarter mile of an existing school.

Facility 5: This facility currently manufactures ammonia for use on-site as well as for sale, so for the new SCRs that may be installed, they could potentially be connected to the existing piping to receive ammonia, without installing new storage tanks. Even if new storage tanks are installed, because of the existing ammonia plant and the amount that is currently permitted in this system, this facility's current potential for an offsite consequence of ammonia is considered part of the existing setting or baseline. Thus, the installation of new SCRs at this facility would not be expected to create a new offsite consequence that would affect the nearby school.

Facility 7: This facility's representatives have indicated that the recent installation of a new ammonia storage tank was specifically installed and permitted with an ammonia throughput limit sufficient to accommodate the projected ammonia needs from implementing anticipated future SCR projects in response to the December 2015 amendments to NOx RECLAIM as well for the currently proposed project. A risk consequence analysis was performed for this recently installed ammonia tank and the analysis concluded that the toxic endpoint would not leave the property boundaries. Thus, the installation of new SCRs at this facility would not be expected to create a new offsite consequence that would affect the nearby school as no additional new installations of ammonia storage tanks would be necessary.

Facility 10: As mentioned previously in the ammonia rupture scenario discussion, this facility's representatives have indicated that they intend to utilize an existing SCR equipped with an existing ammonia tank to achieve the BARCT NOx emission limit in PR 1109.1. For this reason, Facility 10 would not be expected to contribute to a new offsite consequence associated with a ruptured ammonia storage tank, regardless of the size of the existing tank and its current location, to comply with the currently proposed project. Thus, if this facility repurposes an existing SCR and ammonia tank for their boiler, no new installations of an ammonia storage tank may be necessary such that no new offsite consequences that would affect the nearby school would be expected.

In general, when identifying the type of receptor and the distance of equipment to a receptor location, facilities should adhere to the current South Coast AQMD risk assessment procedures[17] which identify how to measure receptor distances for both a point source and volume source. Since it is speculative to predict or forecast where these individual facilities will choose to site their new ammonia tanks, if at all, it is not possible to quantify the exact toxic endpoint distance that will result from compliance with PR 1109.1 and whether the toxic endpoint would extend beyond each facility's boundaries. Therefore, it is not possible to conclusively determine that schools located near the aforementioned facilities would be outside the toxic endpoint distance if there was an ammonia release. For this reason, this SEA is concluding that implementation of the proposed project could potentially cause significant adverse impacts from hazardous emissions onsite or the handling of acutely hazardous materials associated with ammonia near schools.

<u>Summary</u>
Table 4.3-3 summarizes the substances for the various processes at the affected facilities that were previously analyzed in the December 2015 Final PEA for NOx RECLAIM that are also applicable to the currently proposed project analyzed in this SEA.

Table 4.3-3
Substances Previously Analyzed in the December 2015 Final PEA for NOx RECLAIM that May Also Apply to PR 1109.1

Substance	Potential Overall Increase, Decrease, or No Change from Existing Setting?	Contains TAC(s) per South Coast AQMD Rule 1401?	Hazardous per CalARP?	NFPA Rating: Health (Blue)	NFPA Rating: Flammability (Red)	NFPA Rating: Reactivity (Yellow)	NFPA Rating: Special (White)
NH3 (19% by weight)	Increase	Yes, Chronic & Acute (non-cancer)	Yes	3	1	0	None
Fresh Catalyst	Increase	No	No	N/A	N/A	N/A	N/A
Spent Catalyst	Increase	No	No	N/A	N/A	N/A	N/A

[17] South Coast Air Quality Management District Risk Assessment Procedures for Rules 1401, 1401.1 and 212, Version 8.1, September 1, 2017 http://www.aqmd.gov/docs/default-source/permitting/rule-1401-risk-assessment/riskassessproc-v8-1.pdf

NFPA Hazard Code Key: 4 = Extreme; 3 = High; 2 = Moderate; 1 = Slight; 0 = Insignificant; N/A = NFPA hazard is not assigned.

Of the substances listed, only ammonia is considered hazardous. and a net increase in its use is expected to occur as part of implementing PR 1109.1. The effects of the increased use of ammonia are previously analyzed in the "Ammonia" discussion in the December 2015 Final PEA for NOx RECLAIM[18]. There are no other changes or net increases to any of the other hazardous substances that were previously analyzed in the December 2015 Final PEA for NOx RECLAIM that would result in a significant adverse impact for hazards and hazardous materials for PR 1109.1.

[18] South Coast AQMD, December 2015 Final PEA for NOx RECLAIM, Subchapter 4.4, pp. 4.4-9 to 4.4-13.

Project-Specific Impacts – Conclusion

Installation of new SCRs and associated ammonia storage tanks and the upgrades of existing SCRs as a result of implementing the proposed project will be expected to comply with applicable design codes and regulations, conform to NFPA standards, and conform to regulations or generally accepted industry practices related to operating policy and procedures concerning the design, construction, security, leak detection, spill containment or fire protection. However, based on the preceding description of hazards and hazardous materials impacts and ammonia release scenarios which consider the toxic endpoint concentration of 0.14 mg/L which is equivalent to ERPG 2 levels, **the proposed project is expected to generate significant adverse hazards and hazardous materials impacts for the routine transport, use, and storage of ammonia**. However, even though hazards associated with ammonia are significant, it should be noted that the incremental amount of ammonia that is expected to be needed to implement the proposed project is substantially less than what was previously analyzed in the December 2015 Final PEA for NOx RECLAIM. For the fresh and spent catalyst listed in Table 4.3-3, the proposed project is expected to generate less than significant hazards and hazardous materials impacts since SCR catalysts are not hazardous. To the extent that future projects to install new or modify existing NOx controls conforms with the hazard analysis in this SEA, no further hazard analysis may be necessary. However, if site-specific characteristics are involved with future projects that are outside the scope of this analysis, further hazards analysis may be warranted.

Project-Specific Mitigation: If significant adverse environmental impacts are identified in a CEQA document, the CEQA document shall describe feasible measures that could minimize the significant adverse impacts. [CEQA Guidelines Section 15126.4]. Therefore, feasible mitigation measures to reduce the risk of an offsite consequence due to the catastrophic rupture of an ammonia tank are required.

The analysis concluded that the hazards and hazardous materials impacts from implementing the proposed project are considered to be significant and adverse for the routine transport, use, and storage of ammonia. Therefore, mitigation measures are required. However, no feasible mitigation measures have been identified for the transportation of ammonia, over and above the extensive safety regulations that currently apply to delivery trucks that haul ammonia. For fresh and spent catalyst, the analysis concluded that the proposed project is expected to generate less than significant hazards and hazardous materials impacts since SCR catalysts are not hazardous.

For any facility seeking to install a new SCR system and the accompanying ammonia storage tank for combustion equipment subject to PR 1109.1, a permit application will need to be submitted. Thus, South Coast AQMD staff will review the application and determine whether the project is covered by the analysis in this SEA or whether additional CEQA review is needed.

The following mitigation measures are required for any facility whose operators choose to install a new aqueous ammonia storage tank and the offsite consequence analysis indicates that sensitive receptors will be located within the toxic endpoint distance. In addition, these mitigation measures will be included in a Mitigation, Monitoring, and Reporting plan as part of issuing South Coast AQMD permits to construct for the facility-specific project. These mitigation measures will be enforceable by South Coast AQMD personnel.

HZ-1 Require the use of aqueous ammonia at concentrations less than 19 percent by weight.

HZ-2 Install safety devices, including but not limited to: continuous tank level monitors (e.g., high and low level), temperature and pressure monitors, leak monitoring and detection system, alarms, check valves, and emergency block valves.

HZ-3 Install secondary containment such as dikes and/or berms to capture 110 percent of the storage tank volume in the event of a spill.

HZ-4 Install a grating-covered trench around the perimeter of the delivery bay to passively contain potential spills from the tanker truck during the transfer of aqueous ammonia from the delivery truck to the storage tank.

HZ-5 Equip the truck loading/unloading area with an underground gravity drain that flows to a large on-site retention basin to provide sufficient ammonia dilution to minimize the offsite hazards impacts to the maximum extent feasible in the event of an accidental release during transfer of aqueous ammonia.

HZ-6 Install tertiary containment that is capable of evacuating 110 percent of the storage tank volume from the secondary containment area.

Implementing Mitigation Measures HZ-1 through HZ-6 would be expected to prevent a catastrophic release of ammonia from leaving the facility property and exposing offsite sensitive receptors; however, as an abundance of caution, due to the anticipated number of affected facilities and without detailed information specific to each facility's layout and plan of action for compliance, the overall conclusion is that hazards and hazardous materials impacts for PR 1109.1 will remain significant after mitigation measures are applied.

Remaining Impacts After Mitigation: The hazards and hazardous materials analysis concluded that potential hazards and hazardous materials impacts for ammonia transport/deliveries would be significant such that mitigation measures are required. However, because there are no feasible mitigation measures, over and above the extensive safety regulations that currently apply to delivery trucks that haul ammonia, to reduce ammonia transportation impacts to less than significant, the hazards and hazardous materials impacts for the ammonia deliveries remain significant. In addition, although the aforementioned mitigation measures, if employed, would reduce the hazards and hazardous materials impacts from aqueous ammonia, they are not expected to reduce impacts to less than significant. **Therefore, the remaining hazardous and hazardous materials impacts from exposure to the ERPG 2 level of 0.14 mg/L of aqueous ammonia due to tank rupture are considered to be significant after mitigation.**

For the fresh and spent catalyst, the hazards and hazardous materials analysis concluded that potential hazards and hazardous materials impacts would be less than significant, such that no mitigation measures are required. Thus, the hazards and hazardous materials impacts for these SCR catalyst remain less than significant.

4.3.3 Cumulative Hazards and Hazardous Materials Impacts

Adverse impacts from an accidental release of aqueous ammonia are localized impacts (i.e., the impacts are isolated to the area around the affected facility). However, to the extent that affected facilities are located near other facilities that have hazardous materials risks, the cumulative adverse hazard impacts from this project could contribute to existing nearby hazard risks from other projects. **Because the project-specific hazards and hazardous materials impacts for ammonia transport, use, and storage would potentially create significant impacts, they are considered to be cumulatively considerable pursuant to CEQA Guidelines Section 15064 (h)(1) and therefore, generate significant adverse cumulative hazards and hazardous materials impacts**.

For the fresh and spent catalyst, the project-specific hazards and hazardous materials impacts do not exceed any applicable significance thresholds because SCR catalyst is not considered a hazardous material and thus will not create a hazards impact; **thus, the use of additional SCR catalyst is not considered to be cumulatively considerable pursuant to CEQA Guidelines Section15064 (h)(1) and therefore, would not generate significant adverse cumulative hazards and hazardous materials impacts**.

In addition, CEQA Guidelines Section 15130 (d) states "No further cumulative impacts analysis is required when a project is consistent with a general, specific, master or comparable programmatic plan where the lead agency determines that the regional or areawide cumulative impacts of the proposed project have already been adequately addressed in section 15152(f), in a certified EIR for that plan."

The proposed project as evaluated in this SEA is consistent with the 2016 AQMP because it implements a control measure CMB-05 contained in the 2016 AQMP and analyzed in the EIR for the AQMP. The EIR for the AQMP analyzed the impacts, including cumulative impacts, from all of the control measures in the 2016 AQMP. The regional cumulative impacts of the proposed project have already been adequately addressed in the certified March 2017 Final Program EIR for the 2016 AQMP.

The 2016 AQMP is a regional plan that includes all the measures, whether regulatory or incentive-based, that are included in the AQMP to help attain the national ambient air quality standards. As such, March 2017 Final Program EIR evaluated the environmental impacts associated with implementing the 2016 AQMP stationary and mobile source control measures to determine whether or not the impacts of the project are cumulatively considerable when combined with potential impacts associated with other similar regional projects involving regulatory activities or other projects with similar impacts. The 2016 AQMP control measures consist of three components: 1) the South Coast AQMD's Stationary and Mobile Source Control Measures (which includes CMB-05 and the RECLAIM Transition project; 2) State and Federal Mobile Source Control Measures; and 3) Regional Transportation Strategy and Control Measures provided by SCAG. The cumulative impacts analysis for the March 2017 Final Program EIR also included the project-specific analyses of the South Coast AQMD's stationary and mobile source control measures and CARB's mobile source control measures, as well as the transportation control measures (TCMs) that were developed and adopted by the Southern California Association of Governments (SCAG) as part of the 2016 Regional Transportation Plan/Sustainable Communities Strategy RTP/SCS) and the 2015 Federal Transportation Improvement Program (FTIP)[19]. The TCMs are appropriately part of the cumulative impact analysis because they include regulatory activities associated with measures that could also generate related environmental impacts within

[19] South Coast AQMD, 2016 AQMP, Appendix IV-C.

the Basin. The cumulative impacts analysis was conducted for each of the CEQA topic areas. The current proposed project is consistent with and implements the AQMP Control Measure CMB-05, which was included in the previous cumulative impact analysis. This analysis adequately addressed the cumulative impacts of the proposed project. Thus, no further cumulative impacts analysis is required. [CEQA Guidelines Section 15130(d)].

4.3.4 Cumulative Mitigation Measures

Because the project-specific hazards and hazardous materials impacts are considered to be cumulatively considerable for ammonia transport, use, and storage, cumulative mitigation measures for hazards and hazardous materials impacts for ammonia transport, use, and storage are required. However, since no feasible mitigation measures have been identified, over and above the extensive safety regulations that currently apply to delivery trucks that haul ammonia, no feasible cumulative mitigation measures for ammonia transport/deliveries have been identified since the South Coast AQMD does not have jurisdictional authority to regulate delivery trucks that haul ammonia.

Project-specific mitigation measures have been identified in Section 4.3.3 and will be required for ammonia storage and use. However, no other additional mitigation measures have been identified over and above the extensive safety regulations that currently apply to the use and storage of ammonia., Thus, no feasible cumulative mitigation measures for ammonia use and storage have been identified that would reduce cumulative impacts from hazards and hazardous materials to less than significant. However, impacts remain significant even after mitigation for ammonia use and storage. Therefore, cumulative hazards and hazardous materials impacts remain significant; however, because no additional mitigation measures were identified, no cumulative mitigation measures for hazards and hazardous materials impacts for ammonia transport, use, and storage are imposed.

For fresh and spent catalyst , because the project-specific hazards and hazardous materials impacts are not considered to be cumulatively considerable since SCR catalyst is not hazardous, no cumulative mitigation measures for hazards and hazardous materials impacts for SCR catalyst is required.

SUBCHAPTER 4.4

HYDROLOGY

4.4 HYDROLOGY

PR 1109.1 proposes to reduce NOx emissions from refinery equipment and transition equipment that is currently permitted under the NOx RECLAIM program to a command-and-control regulatory structure by requiring affected equipment operating at RECLAIM or former RECLAIM facilities to comply with current BARCT.

This chapter independently considers the currently proposed project and analyzes the incremental changes, if any, relative to the baseline which is the project analyzed in the December 2015 Final PEA for NOx RECLAIM. The December 2015 Final PEA for NOx RECLAIM previously analyzed hydrology (water demand) impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS at 20 facilities, with nine from the refinery sector and 11 from the non-refinery sector. The NOP/IS for the Draft PEA for NOx RECLAIM identified the environmental topic of hydrology (water demand) impacts as having potentially significant adverse impacts which were further analyzed in the December 2015 Final PEA for NOx RECLAIM and concluded that significant adverse impacts to hydrology (water demand) would occur.

Seven additional facilities and additional equipment categories will apply to the proposed project when compared to the project analyzed in December 2015 Final PEA for NOx RECLAIM for 20 facilities, with nine from the refinery-sector. However, the same types of air pollution control equipment with similar impacts to the same environmental topic areas that were previously analyzed are expected to occur with the proposed project except that the proposed project will have an incremental increase in the number of new SCRs installed with the associated ammonia storage tanks and the number of existing SCRs upgraded. The proposed project is also expected to involve the replacement of existing burners with ULNBs and these activities were not previously analyzed in the December 2015 Final PEA for NOx RECLAIM. While SCRs and ULNBs do not use water for their operation, additional construction activities associated with installing the additional new SCRs installed with the associated ammonia storage tanks means that additional water will be needed for fugitive dust suppression and for hydrotesting the new ammonia storage tanks. Thus, this SEA updates the previous hydrology (water demand) impacts analysis conducted in the December 2015 Final PEA for NOx RECLAIM to reflect these changes.

The hydrology analysis in this SEA identifies the net effect of implementing the proposed project in comparison to what was previously analyzed in the December 2015 Final PEA for NOx RECLAIM.

4.4.0 Introduction

As previously summarized in Table 4.1-1, various BARCT control technology options are available for each category of combustion equipment. This SEA tiers off two previous programmatic CEQA documents, the December 2015 Final PEA for NOx RECLAIM and the March 2017 Final Program EIR for the 2016 AQMP. This SEA is a subsequent document to the December 2015 Final PEA for NOx RECLAIM. Because this is a subsequent document, the baseline is the project analyzed in the December 2015 Final PEA for NOx RECLAIM.

The December 2015 Final PEA for NOx RECLAIM specifically evaluated hydrology impacts during construction activities associated with installing the various control equipment when soil disturbance is involved, and during operation from new or modified add-on air pollution control equipment that use water for their operation, e.g., scrubbers such as LoTOx^{TM} with WGS. The December 2015 Final PEA for NOx RECLAIM also analyzed water use associated with hydrotesting the ammonia storage tanks.

The proposed project applies to 16 facilities and nine of these facilities were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Even though more facilities and more combustion equipment categories will be affected by the proposed project, the key differences between the analysis in December 2015 Final PEA for NOx RECLAIM and this SEA for the proposed project is that this SEA will need to update the previous CEQA analysis relative to hydrology impacts to: 1) adjust the amount of water that will be needed for dust mitigation during construction when soil disturbance is involved to account for the installation of additional new SCRs and associated ammonia storage tanks; and 2) adjust the quantity of water needed to conduct hydrotesting of the new ammonia storage tanks after they are installed.

While the currently proposed project will be expected to install additional new SCRs and upgrade existing SCRs when compared to the previous analysis the December 2015 Final PEA for NOx RECLAIM, since SCR technology does not utilize water for its operation, no increases in operational water are anticipated as a result of these changes. Also, while the proposed project may involve the installation of LoTOx^{TM} with WGSs, which utilize water for their operation, these air pollution control devices and the associated water use were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Moreover, the proposed project neither contains any changes to the type of combustion equipment that would utilize LoTOx^{TM} with WGSs nor requires any updates to the amount of water use that will be needed for their operation. Thus, an updated hydrology analysis of scrubber-related impacts will not be required for this SEA.

Finally, while the potential for replacing existing burners with ULNBs in some combustion equipment and the associated environmental impacts were not previously analyzed in the December 2015 Final PEA for NOx RECLAIM, a new hydrology analysis of ULNB-related impacts will also not be required for this SEA for neither construction nor operation since the installation of ULNBs do not involve construction activities that would disturb soil and cause fugitive dust and ULNBs do not require any water for their operation.

Thus, the hydrology analysis in this SEA focuses on the changes in water use for fugitive dust control during construction of the additional new SCRs and associated ammonia storage tanks and for hydrotesting of ammonia storage tanks after they are installed as part of implementing the proposed project when compared to the previous hydrology impact analysis in the December 2015 Final PEA for NOx RECLAIM.

4.4.1 Significance Criteria for Hydrology

Potential impacts on water resources will be considered significant if any of the following criteria apply:

Water Demand:

- The project increases demand for total water by more than five million gallons per day.
- The existing water supply does not have the capacity to meet the increased demands of the project, or the project would use more than 262,820 gallons per day of potable water.

The significance threshold of five million gallons per day was determined by converting the 4,000 acre-feet per year conclusion of significance in the 1990 State Implementation Plan for PM10 in the Coachella Valley, into gallons. There are 325,851 gallons per acre-feet and 260 working days per year; please refer to the previous document for a discussion on the significance conclusion of 4,000 acre-feet per year.[20]

$$\frac{4{,}000\ acre-feet}{year} x \frac{325851\ gallons}{acre-feet} x \frac{1\ year}{260\ working\ days} \cong 5{,}000{,}000\ gallons\ per\ day$$

Regarding the significance threshold for potable water, CEQA Guidelines Section 15155(a)(1)(C) defines a water demand project as "A commercial office building employing more than 1,000 persons or having more than 250,000 square feet of floor space." To estimate what this means in terms of water demand per person relative to the square footage (sf) of the floor area of the plant, commercial water usage rates[21] and average employment levels[22] (i.e. the number of employees per square foot) can be applied as follows:

$$\frac{123\ gallons}{year \cdot SF\ building} x \frac{1{,}000\ SF\ building}{1.8\ employees} x \frac{1\ year}{260\ working\ days} x1000\ employees$$

$$= 262{,}820\ gallons\ per\ day\ of\ potable\ water$$

4.4.2 Potential Hydrology Impacts and Mitigation Measures

The key effects of implementing the proposed project and the determination of which aspects may involve hydrology impacts focus on: 1) the anticipated increase of water needed for fugitive dust mitigation during construction as part of installing the additional new SCRs and associated ammonia storage tanks; and, 2) the anticipated increase in water needed to hydrotest the additional new ammonia storage tanks before bringing them online for operation.

[20] 1990 State Implementation Plan for PM10 in the Coachella Valley, SCH. No. 90020391; South Coast AQMD, 1991

[21] California Commercial End-Use Survey, Consultant Report, Table 8-1, p 150. Prepared For: California Energy Commission, Prepared by: Itron, Inc. March 2006. http://www.energy.ca.gov/2006publications/CEC-400-2006-005/CEC-400-2006-005.pdf

[22] Urban Land Use Institute Data, Wausau West Industrial Park Expansion, Development Impact Analysis, Average Employment Levels, p.4, Prepared by Vierbicher Associates, January 5, 2001.

Table 4.4-1 summarizes the estimated number of NOx emission control devices that were not previously analyzed the December 2015 Final PEA for NOx RECLAIM but will be analyzed in this SEA because they may be installed as part of implementing PR 1109.1.

Table 4.4-1
Estimated Number of NOx Air Pollution Control Devices Per Equipment Category for Refineries subject to PR 1109.1 Not Previously Analyzed Under NOx RECLAIM

Equipment Category	Number of Affected Facilities	Estimated Number of Air Pollution Control Devices Not Previously Analyzed in the December 2015 Final PEA for NOx RECLAIM
Refinery Process Heaters and Boilers	9	~~59~~ 47 Burner Replacements with ULNBs ~~20~~ 25 New SCRs ~~6~~ 3 SCR Upgrades 9 Heater/Boiler Replacements
SRU/TGs	4	5 Burner Replacements with ULNBs
Thermal Oxidizers	4	8 Burner Replacements with ULNBs
Refinery Gas Turbines	1	1 SCR Upgrade
	TOTAL	**~~20~~ 25 New SCRs** **~~7~~ 4 SCR Upgrades** **~~72~~ 60 Burner Replacements with ULNBs** **9 Heater/Boiler Replacements**

Of the above five additional new SCR installations, Facility 1 would install one less SCR and Facility 4 would install six more SCRs. However, the total number of SCR installations that are expected to occur on a peak day, and thus require hydrotesting, is expected to be one less (due to Facility 1 installing one less SCR). For practical reasons, Facility 4 is not expected to install more than six SCRs on a given day, the amount analyzed in the Draft SEA. Thus, the hydrology (water demand) impacts analyzed in the Draft SEA would be more conservative than an updated analysis with one less SCR installation on a peak day.

Water is not needed to operate any of the NOx air pollution control devices listed in Table 4.3-1. Since no ground disturbance would be required for replacing burners with ULNBs in various combustion equipment or with upgrading existing SCRs, water is anticipated to be needed during construction only for installing new SCRs and the associated ammonia storage tanks. In addition, post-construction, but prior to operation, the newly installed ammonia storage tanks will first be required to undergo hydrotesting which utilizes water in order to determine if there are any leaks. As such, construction water during fugitive dust mitigation and hydrotesting water are the focus of the hydrology impacts analysis in this SEA.

4.4.2.1 Hydrology Impacts During Construction

As previously summarized in Table 4.4-1, the proposed project is expected to result in the installation of 20 additional, new SCRs and associated ammonia storage tanks, upgrades to seven existing SCRs and replacing burners with ULNBs in 72 combustion devices that were not previously analyzed in the December 2015 Final PEA for NOx RECLAIM.

During installation of the 20 additional, new SCRs and associated ammonia storage tanks, adverse hydrology impacts may occur during construction due to water that may be applied to suppress fugitive dust as required by South Coast AQMD Rule 403. Depending on the proposed location within each facility's boundaries for siting the new SCRs and associated ammonia storage tanks, construction activities such as digging, earthmoving, grading, slab pouring, or paving could occur if the proposed location for the new SCRs and ammonia storage tanks is not suitable in its present form (e.g., graded with a foundation slab). Table 4.4-2 contains a summary of the estimates of the additional plot space needed for each facility identified as potentially installing the ~~20~~ 25 additional, new SCRs and associated ammonia storage tanks. The largest parcel of land to be potentially disturbed at any one facility could occur at Refinery 4 and is approximately 3,545 square feet.

Table 4.4-2
Potential Plot Space and Water Needed to Construct ~~20~~ 25 Additional, New SCRs and Associated 11,000 Gallon Ammonia Storage Tanks at Refineries subject to PR 1109.1 But Not Previously Analyzed Under NOx RECLAIM

Facility ID	Plot Space Needed for New SCRs (sf)	Number of New Ammonia Storage Tanks Needed	Plot Space Needed for One New Ammonia Storage Tank (sf)	Plot Space Needed for All New Ammonia Storage Tanks (sf)	Total Plot Space for All New SCRs + New Ammonia Storage Tanks (sf)
1	150	~~3~~ 2	539	~~1,617~~ 1,078	~~1,767~~ 1,228
4	311	~~6~~ 12	539	~~3,234~~ 6,468	~~3,545~~ 6,779
5	634	3	539	1,617	2,251
6	1,027	2	539	1,078	2,105
7	570	2	539	1,078	1,648
9	1,276	3	539	1,617	2,893
10	31	1	539	539	570
Key: sf = square feet		**~~20~~ 25**	**Total**	**~~10,780~~ 13,475**	**~~14,779~~ 17,474**

The amount of plot space needed per facility as presented in Table 4.4-2 directly correlates to how much soil may be disturbed and how much water may be needed for dust suppression during construction of the new SCRs and associated ammonia storage tanks. To comply with the dust suppression requirements in South Coast AQMD Rule 403 – Fugitive Dust, during site preparation activities, some water is expected to be used. To minimize fugitive dust, a minimum of watering two times per day is required. However, on windy days, it may be necessary to conduct a third water application.

At a peak watering rate of three applications per day at 1/16″ depth (equivalent to 0.005 ft) for ~~14,779~~ 17,474 square feet of plot space disturbed, the peak amount of water that could be used for site preparation/dust suppression construction of foundations for ~~20~~ 25 additional, new SCRs and associated ammonia storage tanks is ~~1,658~~ 1,961 gallons per day (~~14,779~~ 17,474 ft^2 x 0.005 ft x 7.48 gal/ft^3 x 3 watering events). For context, the December 2015 Final PEA for NOx RECLAIM estimated that the amount of water needed for dust suppression activities would be approximately 12,501 gallons per day. The assumption that all facilities will be performing construction on the same day, and thus simultaneously requiring water, is conservative.

When combining the water demand impacts from this SEA and the December 2015 Final PEA for NOx RECLAIM, the potential increase in water use for the facilities that may need to conduct watering for dust suppression activities is less than the South Coast AQMD's significance threshold of 262,820 gallons per day of potable water and five million gallons per day of total water (e.g., potable, recycled, and groundwater).

It is important to note that even if a foundation for the new SCRs and associated ammonia storage tanks needs to be constructed, earth moving activities during site preparation phase of construction are expected to be of a short duration lasting from two to three days to no longer than one month. As such, the corresponding fugitive dust suppression activities are also not expected to last longer than one month. Further, water used for dust suppression purposes does not have to be of potable quality, but can be recycled water. Nonetheless, the amount of water that may be used on a daily basis for dust suppression activities during construction is less than significant. Once the site preparation phase is completed, the need for water for dust suppression purposes will cease.

Instead of installing new SCRs and ammonia storage tanks, facility operators may choose to upgrade their existing SCRs which involves replacing the existing catalyst in the SCR housing. For SCR upgrades, site preparation activities are not expected to be necessary because no changes to the existing foundation and the existing SCR equipment are expected to be necessary since it will re-used in their current location and current plot space. Therefore, no water for dust suppression purposes is expected to be needed for any SCR upgrade activities.

Once constructed, but prior to operation, additional water is expected to be used to hydrostatically (pressure) test, also referred to as "hydrotest," all new installed ammonia storage tanks and connective piping to ensure the integrity of each structure's integrity. Pressure testing or hydrotesting is typically a one-time event, unless a leak is found. Similar to dust suppression, water used for pressure testing does not have to be of potable quality, but can be recycled water. In addition, water used during hydrotesting can be sent somewhere else within a facility for future re-use. For example, in the Final Negative Declaration for the Phillips 66 Los Angeles Refinery Carson Plant – Crude Oil Storage Capacity Project[23], water used during hydrotesting of the crude storage tank was later sent to hydrotest another smaller tank being built as part of the project. Afterwards, the water from the hydrotesting was transferred to a fire water tank that supplies process water to the refinery so that no water was wasted as a result of hydrotesting.

[23] South Coast AQMD, Final Negative Declaration for the Phillips 66 Los Angeles Refinery Carson Plant – Crude Oil Storage Capacity Project, SCH No. 2013091029, December 2014, p. 2-57. http://www.aqmd.gov/docs/default-source/ceqa/documents/permit-projects/2014/phillips-66-fnd.pdf

Table 4.4-3 contains a summary of the amount of water that may be needed to hydrotest the ~~20~~ 25 additional new ammonia storage tanks that were not previously analyzed in December 2015 Final PEA for NOx RECLAIM.

Table 4.4-3
Total Amount of Water Needed for Hydrotesting 20 Additional, New Ammonia Storage Tanks at Refineries subject to PR 1109.1 But Not Previously Analyzed Under NOx RECLAIM

Facility ID	Number of New Ammonia Storage Tanks Needed	Capacity of New Ammonia Storage Tanks (gallons)	Number of Tanks Overlapping Construction per day *(assumes 1/3rd of total number of tanks)*	Amount of Water Needed to Hydrotest during Overlap (gallons)	Total Water Needed to Hydrotest for Entire Project (gallons)
1	~~3~~ 2	11,000	1	11,000	33,000
4	~~6~~ 12	11,000	2*	22,000	66,000
5	3	11,000	1	11,000	33,000
6	2	11,000	1	11,000	22,000
7	2	11,000	1	11,000	22,000
9	3	11,000	1	11,000	33,000
10	1	11,000	1	11,000	11,000
TOTAL	**~~20~~ 25**		**8**	**88,000**	**~~220,000~~ 286,000**

* While Facility 4 will be installing six more SCRs, for practical reasons, the facility is not expected to install more than six SCRs on a given day, the amount analyzed in the Draft SEA. Thus, the amount of water needed to hydrotest during overlap is expected to stay the same as previously analyzed, while the total amount of water needed to hydrotest for the entire project has been updated.

As shown in Table 4.4-3, the potential increase in water use for all seven facilities conducting overlapping hydrotesting activities on an overlap day is less than South Coast AQMD's significance threshold of 262,820 gallons per day of potable water and five million gallons per day of total water (e.g., potable, recycled, and groundwater). Thus, the amount of potable water that may be used on a daily basis for hydrotesting activities post-construction but prior to operation is less than significant. Further, the potential increase in water use for all seven facilities conducting hydrotesting activities for the entire project (this includes all tanks, more than the assumption of 1/3 of total tanks) is less than South Coast AQMD's significance threshold of five million gallons per day of total water.

For context, Table 4.4-4 presents the original projections in the December 2015 Final PEA for NOx RECLAIM of how much water would be needed to conduct hydrotesting at the refinery facilities.

Table 4.4-4
Hydrotesting Water Estimates For Refineries Previously Analyzed Under NOx RECLAIM

Facility ID	No. of NH3 storage tanks needed	Size of NH3 storage tanks needed (gallons)	Number of Tanks Overlapping Construction per day *(assumes 1/3rd of total number of tanks)*	Gallons of Water Needed to Hydrotest during Overlap	Gallons of Water Needed to Hydrotest for Entire Project
1	15	11,000	5	55,000	165,000
2	1	11,000	1	11,000	11,000
3	2	11,000	1	11,000	22,000
4	6	11,000	2	22,000	66,000
5	17	11,000	6	66,000	187,000
6	17	11,000	6	66,000	187,000
7	10	11,000	3	33,000	110,000
8	9	11,000	3	33,000	99,000
9	7	11,000	2	22,000	77,000
TOTAL	**84**		**29**	**319,000**	**924,000**

Source: December 2015 Final PEA for NOx RECLAIM, Subchapter 4.5, Table 4.5-6

When combining the water demand impacts from this SEA and the December 2015 Final PEA for NOx RECLAIM, the amount of potable water that could be concurrently used on a daily basis for conducting hydrotesting activities post-construction but prior to operation is potentially significant. However, the potential increase in total water remains less than the South Coast AQMD's significance threshold of five million gallons per day of total water. Thus, the amount of total water -as distinguished from potable water- that may be used for hydrotesting activities post-construction but prior to operation for the entire project is less than significant.

Construction Conclusion

Construction Dust Suppression: Less than significant adverse water demand impacts are expected during construction of the proposed project.

Hydrotesting Post-Construction: Potentially significant adverse water demand impacts from hydrotesting are expected if potable water is utilized.

4.4.2.2 Mitigation of Construction Hydrology Impacts

Construction Dust Suppression: Less than significant adverse impacts associated with hydrology (water demand) are expected from the proposed project during construction, so no mitigation measures during construction are required.

Post-Construction Hydrotesting: Significant adverse water demand impacts from hydrotesting are expected, if potable water is used, so mitigation measures during hydrotesting are required.

As part of certifying the December 2015 Final PEA for NOx RECLAIM, the South Coast AQMD Governing Board adopted a mitigation monitoring plan which included mitigation measures specific to water demand for conducting hydrotesting and these mitigation measure will continue to apply to the proposed project analyzed in this SEA.[24]

Specifically, for any facility that installs NOx control equipment such as SCR technology that also requires the installation of support equipment, such as a storage tank or other equipment, to be installed and hydrotested as part of the proposed project, South Coast AQMD staff, pursuant to the following mitigation measures, will require facility operators utilize to use current supplies and future supplies of recycled water in accordance with the California Water Code, and if available, pursuant to the HRRWP or other recycled water pipeline if available, to conduct hydrotesting. Alternately, facility operators may substitute the use of purchased recycled water with non-potable water such as treated process water (e.g., cooling tower blowdown water, etc.) that is temporarily re-routed or diverted from elsewhere within the facility.

If, at the time when each facility-specific project is proposed in response to the proposed project, South Coast AQMD staff will conduct a CEQA evaluation of the facility-specific project and determine if the project is covered by the analysis in this SEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing South Coast AQMD permits to construct for the facility-specific project. Based on the preceding discussion, the following water demand mitigation measures during hydrotesting will apply to the proposed project and will be enforceable by South Coast AQMD personnel:

HWQ-1 When support equipment such as a storage tank or other equipment is installed to support operations of installed NOx control equipment and hydrotesting is required prior to operation, the facility operator is required to use, in lieu of potable water, recycled water or other non-potable process water temporarily diverted from elsewhere within the facility, if available, to satisfy the water demand for hydrotesting.

HWQ-2 For hydrotesting purposes, in the event that recycled water cannot be delivered to the affected facility and diverted non-potable process water is not used, the facility operator is required to submit two written declarations with each application for a Permit to Construct for the NOx control equipment and any support equipment such as storage tank or other equipment that requires hydrotesting, one to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project and one from a high-ranking officer at the facility indicating the reason(s) and the supporting evidence that explains why the non-potable process water cannot be diverted to the project from elsewhere within the facility.

[24] South Coast AQMD, Attachment 1 to the Governing Board Resolution for the Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), Findings, Statement of Overriding Considerations and Mitigation Monitoring Plan. December 2015. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2015/regxxfindings.pdf

4.4.2.3 Remaining Construction Hydrology Impacts After Mitigation

Construction Dust Suppression: The hydrology analysis concluded that potential hydrology (water demand) during construction would be less than significant, so no mitigation measures are required during construction. Thus, hydrology impacts during construction remain less than significant.

Hydrotesting Post-Construction – Water Demand: The hydrology analysis concluded that potential water demand impacts during hydrotesting would be significant, if potable water is used, so mitigation measures are required during hydrotesting. The water demand analysis during hydrotesting shows that the potential increase in potable water use cannot be fully satisfied either with all recycled water or a combination of non-potable water such as process water and recycled water, since some potable water may still be required for certain facilities. The use of non-potable water such as recycled water and diverted process water can help substantially reduce the water demand impacts to a less than significant level if facility operators that have access to recycled water or diverted non-potable process water are required to use recycled water, if available, or diverted non-potable process water. Further, the use of other non-potable process water temporarily diverted from elsewhere within the facility is another option that can help substantially reduce the potable water demand impacts to a less than significant level if facility operators that have a way to divert non-potable process water to a location within the facility where hydrotesting will be conducted. For example, for the Phillips 66 Los Angeles Refinery Carson Plant – Crude Oil Storage Capacity Project, water for conducting hydrotesting was satisfied with non-potable groundwater that was temporarily diverted from the fire water tank[25]. In addition, the reuse of hydrotest water, whether the source is recycled water or other non-potable water, for multiple tanks, for example, for other uses within each facility can also help substantially reduce the water demand impacts to a less than significant level. However, because there is no absolute guarantee at the time of this writing that recycled water or other non-potable will be available to all of the affected facilities, the analysis conservatively assumes that potable water may be needed. Therefore, the proposed project will remain significant after mitigation for water demand during hydrotesting.

4.4.2.4 Hydrology Impacts During Operation

While the currently proposed project will be expected to install additional new SCRs and upgrade existing SCRs when compared to the previous analysis the December 2015 Final PEA for NOx RECLAIM, since SCR technology does not utilize water for its operation, no increases in operational water are anticipated as a result of these changes. Also, while the proposed project may involve the installation of LoTOx™ with WGSs, which utilize water for their operation, these air pollution control devices and the associated water use were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Moreover, the proposed project neither contains any changes to the type of combustion equipment that would utilize LoTOx™ with WGSs nor requires any updates to the amount of water use that will be

[25] South Coast AQMD, Final Negative Declaration for: Phillips 66 Los Angeles Refinery Carson Plant – Crude Oil Storage Capacity Project, SCH No. 2013091029, December 12, 2014, p. 2-57. http://www.aqmd.gov/docs/default-source/ceqa/documents/permit-projects/2014/phillips-66-fnd.pdf

needed for their operation. Thus, an updated hydrology analysis of scrubber-related impacts will not be required for this SEA.

Finally, while the potential for replacing existing burners with ULNBs in some combustion equipment and the associated environmental impacts were not previously analyzed in the December 2015 Final PEA for NOx RECLAIM, a new hydrology analysis of ULNB-related impacts will also not be required for this SEA for since the installation of ULNBs do not require any water for their operation. Thus, there is no water demand during operation for the currently proposed project in this SEA.

For context, Table 4.4-5 presents the original projections in the December 2015 Final PEA for NOx RECLAIM of how much water would be needed at the refinery facilities during operation.

Table 4.4-5
Water Estimates Previously Analyzed for Refineries Under NOx RECLAIM

Facility ID	Potential NOx Control per Equipment/Source Category	Potential Increase in Operational Water Demand (gal/day)
1	SRU/TGU: 1 LoTOx™ with WGS	70,000
2	Coke Calciner: 1 LoTOx™ with WGS	40,896
4	FCCU: 1 LoTOx™ with WGS	49,315
5	SRU/TGU: 2 LoTOx™ with 2 WGSs	219,178
6	SRU/TGU: 1 LoTOx™ with WGSs	109,589
8	SRU/TGU: 1 LoTOx™ with WGS	70,000
9	FCCU: 1 LoTOx™ with WGS	43,836
	TOTAL	**602,814**

Source: December 2015 Final PEA for NOx RECLAIM, Subchapter 4.5, Table 4.5-9

As shown in Table 4.4-5, the water demand analysis in the December 2015 Final PEA for NOx RECLAIM concluded that the South Coast AQMD's significance threshold of five million gallons per day for total water (e.g., potable, recycled, and groundwater) would not be exceeded. However, if all the water needed to operate the NOx control equipment summarized in Table 4.4-5 were supplied with potable water, South Coast AQMD's significance threshold of 262,820 gallons per day of potable water would be exceeded. Thus, the amount of potable water that could potentially be used on a daily basis for during operation was concluded to have significant adverse water demand impacts.

Thus, the water demand analysis in the December 2015 Final PEA for NOx RECLAIM also acknowledged that Refineries 1, 5 and 6 have a high potential to use recycled water, instead of potable water, to operate the NOx control equipment because of their current access recycled water and that Refineries 4, 8, and 9 were in negotiations to obtain future access to recycled water. Finally, the water demand analysis in the December 2015 Final PEA for NOx RECLAIM recognized that operators of Refinery 2 had multiple NOx control options, which did not all rely the use of water. In any case, the previous analysis showed that the water purveyors would be able to supply potable water to Refinery 2 as well as Refineries 1, 4, 5, 6, 8 and 9, if needed. Nonetheless, the water demand analysis conservatively concluded that significant adverse impacts associated with operational water demand would occur.

Operation Conclusion

While the proposed project evaluated in this SEA would not contribute any new operational water demand impacts, since significant adverse water demand impacts during operation were concluded for the previously proposed project analyzed the December 2015 Final PEA for NOx RECLAIM, the analysis in this SEA is also concluding significant adverse water demand impacts during operation.

4.4.2.5 Mitigation of Operation Hydrology Impacts

The currently proposed project as analyzed in this SEA is not expected to contribute to any new operational water demand impacts. However, the previous analysis of water demand impacts in the December 2015 Final PEA for NOx RECLAIM concluded significant adverse water demand impacts for potable water, so the conclusion of significant adverse water demand impacts remains unchanged. As part of certifying the December 2015 Final PEA for NOx RECLAIM, the South Coast AQMD Governing Board adopted a mitigation monitoring plan which included the following mitigation measures specific to operational water demand and these mitigation measure will continue to apply to the proposed project analyzed in this SEA.[26]

Specifically, the following mitigation measures will apply to any facility whose operator chooses to install NOx control equipment that utilizes water for its operation. If, at the time when each facility-specific project is proposed in response to the proposed project, South Coast AQMD staff will conduct a CEQA evaluation of the facility-specific project and determine if the project is covered by the analysis in this SEA. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing South Coast AQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by South Coast AQMD personnel.

Water Demand: The currently proposed project as analyzed in this SEA is not expected to contribute to any new operational water demand impacts. However, the previous analysis of water demand impacts in the December 2015 Final PEA for NOx RECLAIM, upon which this SEA relies and which is incorporated by reference, concluded that potentially significant adverse impacts associated with operational water demand would be expected. Thus, mitigation measures for operational water demand will continue to be required. Based on the preceding discussion, the following water demand mitigation measures will apply to the proposed project:

[26] South Coast AQMD, Attachment 1 to the Governing Board Resolution for the Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), Findings, Statement of Overriding Considerations and Mitigation Monitoring Plan. December 2015. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2015/regxxfindings.pdf

HWQ-3 When NOx control equipment is installed and water is required for its operation, the facility operator is required to use recycled water, if available, to satisfy the water demand for the NOx control equipment.

HWQ-4 In the event that recycled water cannot be delivered to the affected facility, the facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project.

4.4.2.6 Remaining Operation Hydrology Impacts After Mitigation

Water Demand: The currently proposed project as analyzed in this SEA is not expected to contribute to any new operational water demand impacts but the previous water demand analysis the December 2015 Final PEA for NOx RECLAIM showed that the potential increase in potable water use can be fully satisfied either with all potable water or with a combination of recycled water and potable water, since some potable water may still be required for certain facilities. The use of recycled water can help substantially reduce the water demand impacts to a less than significant level if facility operators that have access to recycled water are required to use recycled water, if available. However, there was no absolute guarantee at the time of writing the December 2015 Final PEA for NOx RECLAIM, upon which this SEA relies and which is incorporated by reference, that future supplies of recycled water could actually be delivered to all of the affected facilities. Therefore, significant water demand impacts after mitigation measures are applied will remain.

4.4.3 Cumulative Hydrology Impacts

Water Demand: Even though the previous water demand analysis in the December 2015 Final PEA for NOx RECLAIM showed that there was a sufficient supply of both potable and recycled water available at the time the CEQA document was certified, because the project-specific water demand impacts have been concluded to be significant due to the uncertainty of the ability for some facilities to receive recycled water and in consideration of California’s on-going drought, the potential water demand impacts continue to be cumulatively considerable pursuant to CEQA Guidelines Section 15064(h)(1). **Therefore, the project is concluded to result in significant adverse cumulative water demand impacts.**

In addition, CEQA Guidelines Section 15130 (d) states “No further cumulative impacts analysis is required when a project is consistent with a general, specific, master or comparable programmatic plan where the lead agency determines that the regional or areawide cumulative impacts of the proposed project have already been adequately addressed in section 15152(f), in a certified EIR for that plan.”

The proposed project as evaluated in this SEA is consistent with the 2016 AQMP because it implements a control measure CMB-05 contained in the 2016 AQMP and analyzed in the EIR for the AQMP. The EIR for the AQMP analyzed the impacts, including cumulative impacts, from all of the control measures in the 2016 AQMP. The regional cumulative impacts of the proposed project have already been adequately addressed in the certified March 2017 Final Program EIR for the 2016 AQMP.

The 2016 AQMP is a regional plan that includes all the measures, whether regulatory or incentive-based, that are included in the AQMP to help attain the national ambient air quality standards. As such, March 2017 Final Program EIR evaluated the environmental impacts associated with implementing the 2016 AQMP stationary and mobile source control measures to determine whether or not the impacts of the project are cumulatively considerable when combined with potential impacts associated with other similar regional projects involving regulatory activities or other projects with similar impacts. The 2016 AQMP control measures consist of three components: 1) the South Coast AQMD's Stationary and Mobile Source Control Measures (which includes CMB-05 and the RECLAIM Transition project; 2) State and Federal Mobile Source Control Measures; and 3) Regional Transportation Strategy and Control Measures provided by SCAG. The cumulative impacts analysis for the March 2017 Final Program EIR also included the project-specific analyses of the South Coast AQMD's stationary and mobile source control measures and CARB's mobile source control measures, as well as the transportation control measures (TCMs) that were developed and adopted by the Southern California Association of Governments (SCAG) as part of the 2016 Regional Transportation Plan/Sustainable Communities Strategy RTP/SCS) and the 2015 Federal Transportation Improvement Program (FTIP)[27]. The TCMs are appropriately part of the cumulative impact analysis because they include regulatory activities associated with measures that could also generate related environmental impacts within the Basin. The cumulative impacts analysis was conducted for each of the CEQA topic areas. The current proposed project is consistent with and implements the AQMP Control Measure CMB-05, which was included in the previous cumulative impact analysis. This analysis adequately addressed the cumulative impacts of the proposed project. Thus, no further cumulative impacts analysis is required. [CEQA Guidelines Section 15130(d)].

4.4.4 Cumulative Mitigation Measures

Water Demand: Even though the currently proposed project as analyzed in this SEA is not expected to contribute to any new operational water demand impacts, because the project-specific water demand impacts during hydrotesting and during operation are considered to be cumulatively considerable when taking into consideration the previous water demand analysis in the December 2015 Final PEA for NOx RECLAIM, cumulative mitigation measures are required.

While the use of recycled water can help substantially reduce the water demand impacts to a less than significant level if facility operators that have access to recycled water are required to use recycled water, if available. However, there was no absolute guarantee at the time of writing the December 2015 Final PEA for NOx RECLAIM, upon which this SEA relies and which is incorporated by reference, that future supplies of recycled water could actually be delivered to all of the affected facilities. Therefore, cumulative significant water demand impacts will remain after mitigation measures are applied.

The South Coast AQMD Governing Board, as part of certifying the December 2015 Final PEA for NOx RECLAIM, adopted a mitigation monitoring plan which included the following mitigation

[27] South Coast AQMD, 2016 AQMP, Appendix IV-C.

measures specific to cumulative water demand impacts and these mitigation measure will continue to apply to the proposed project analyzed in this SEA.[28]

Specifically, the following cumulative water demand mitigation measures will apply to any facility whose operator chooses to install NOx control equipment that utilizes water for its operation. If, at the time when each facility-specific project is proposed in response to the proposed project, South Coast AQMD staff will conduct a CEQA evaluation of the facility-specific project and determine if the project is covered by the analysis in this SEA or the previous analysis in the December 2015 Final PEA for NOx RECLAIM. In addition, these mitigation measures will be included in a mitigation monitoring plan as part of issuing South Coast AQMD permits to construct for the facility-specific project. The mitigation measures will be enforceable by South Coast AQMD personnel.

HWQ-1 When support equipment such as a storage tank is installed to support operations of installed NOx control equipment and hydrotesting is required prior to operation, the facility operator is required to use, in lieu of potable water, recycled water or other non-potable process water temporarily diverted from elsewhere within the facility, if available, to satisfy the water demand for hydrotesting.

HWQ-2 For hydrotesting purposes, in the event that recycled water cannot be delivered to the affected facility and diverted non-potable process water is not used,, the facility operator is required to submit two written declarations with the application for a Permit to Construct for the NOx control equipment and any support equipment such as a storage tank or other equipment that requires hydrotesting, one to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project and one from a high-ranking officer at the facility indicating the reason(s) and the supporting evidence that explains why the non-potable process water cannot be diverted to the project from elsewhere within the facility.

HWQ-3 When NOx control equipment is installed and water is required for its operation, the facility operator is required to use recycled water, if available, to satisfy the water demand for the NOx control equipment.

HWQ-4 In the event that recycled water cannot be delivered to the affected facility, the facility operator is required to submit a written declaration with the application for a Permit to Construct for the NOx control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be delivered to the project.

[28] South Coast AQMD, Attachment 1 to the Governing Board Resolution for the Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), Findings, Statement of Overriding Considerations and Mitigation Monitoring Plan. December 2015. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2015/regxxfindings.pdf

Therefore, cumulative hydrology impacts remain significant; however, because no additional mitigation measures were identified, no cumulative mitigation measures for hydrology impacts are imposed.

4.5 POTENTIAL ENVIRONMENTAL IMPACTS FOUND NOT TO BE SIGNIFICANT

CEQA requires this section of the SEA to identify the environmental topic areas that were analyzed and concluded to have no impacts or less than significant impacts, if the proposed project is implemented. For the effects of a project that were determined not be significant, CEQA Guidelines Section 15128 requires the analysis to contain a statement briefly indicating the reasons that various effects of a project were determined not to have significant impacts and were therefore not discussed in detail.

The proposed project is comprised of PRs 1109.1 and 429.1, PARs 1304 and 2005, and proposed rescinded Rule 1109. The proposed project, PR 1109.1 in combination with supporting rules PR 429.1, PARs 1304 and 2005, and the proposed rescission of Rule 1109, is designed to amend the previous BARCT assessments conducted for: 1) facilities in the refinery sector as previously analyzed in the December 2015 Final PEA for NOx RECLAIM; and 2) Control Measure CMB-05 and the entire RECLAIM Transition project in the 2016 AQMP as previously analyzed in the March 2017 Final Program EIR for the 2016 AQMP. This SEA tiers off of the December 2015 Final PEA for NOx RECLAIM and the March 2017 Final Program EIR for the 2016 AQMP as allowed by CEQA Guidelines Sections 15152, 15162, 15168, and 15385. As explained in the Summary of Chapter 3, the baseline selected for the analysis of the proposed project in this SEA is the project analyzed in the December 2015 Final PEA for NOx RECLAIM.

PR 1109.1 contains BARCT NOx concentration limits which are expected to be achieved primarily by installing new or modifying existing post-combustion air pollution control equipment and utilization of various NOx emission control technologies is expected to create secondary adverse impacts which are analyzed in this CEQA document.

PR 429.1 proposes new requirements for startup, shutdown, and certain maintenance events, including an exemption from the NOx and CO emission limits in PR 1109.1 during these events; and proposes notification and recordkeeping requirements for units that will be subject to PR 1109.1. PARs 1304 and 2005 propose a limited exemption to allow facilities implementing BARCT requirements pursuant to PR 1109.1 to focus on achieving NOx emission reductions without having to concurrently reduce the sulfur content in refinery fuel gas that would otherwise be required by BACT. Since PR 429.1, PAR 1304, PAR 2005, and the proposed rescission of Rule 1109 are rule development activities intended to provide support to the implementation of PR 1109.1, and do not themselves impose any emission reduction requirements, no physical modifications that would create any secondary adverse environmental impacts are expected to occur for this portion of the proposed project. See Section 4.2 of this chapter (see pp. 4.2-55 to 4.2-58) for a review of the requirements in PR 429.1 and PARs 1304 and 2005 as well as the requirements that will be replaced by PR 1109.1 after Rule 1109 is rescinded.

This chapter compares the types of activities and associated environmental impacts with implementing the BARCT standards for the equipment and facilities previously analyzed in the December 2015 Final PEA for NOx RECLAIM, to the additional equipment and sources that will need to comply with the BARCT requirements in PR 1109.1.

This subchapter of the SEA is divided into two sections. The first section identifies the environmental topic areas that were previously concluded in the NOP/IS for the December 2015 Final PEA for NOx RECLAIM to have either less than significant impacts or no impacts (e.g., agriculture and forestry resources; biological resources; cultural and tribal cultural resources; geology and soils; land use and planning; mineral resources; noise; population and housing; public services; and recreation), and as such, were not analyzed further in the December 2015 Final PEA for NOx RECLAIM. This section also assesses whether these previously dismissed environmental topic areas in the December 2015 Final PEA for NOx RECLAIM would be affected by the proposed project. Also, since the new environmental topic area of wildfires was added to the CEQA Guidelines after the December 2015 Final PEA for NOx RECLAIM was certified, this section analyzes whether the proposed project would cause any wildfire-associated impacts.

The second section identifies the environmental topic areas which were previously concluded in the December 2015 Final PEA for NOx RECLAIM to have less than significant impacts and analyzes whether these environmental topic areas would be affected by the proposed project.

<u>Environmental Topic Areas Previously Concluded In The NOP/IS for the December 2015 Final PEA for NOx RECLAIM To Have No Impacts</u>

The following environmental topic areas were previously evaluated in the NOP/IS for the Draft PEA for NOx RECLAIM and were concluded in the December 2015 Final PEA for NOx RECLAIM to have no impacts: agriculture and forestry resources; biological resources; cultural and tribal cultural resources; geology and soils; land use and planning; mineral resources; population and housing; and recreation.

This SEA independently considers the currently proposed project and analyzes the incremental changes, if any, relative to the baseline which is the project analyzed in the December 2015 Final PEA for NOx RECLAIM. While seven additional facilities and additional equipment categories will apply to the proposed project when compared to the project analyzed in December 2015 Final PEA for NOx RECLAIM for the nine refinery-sector facilities, the same types of air pollution control equipment with similar impacts to the same environmental topic areas that were previously analyzed are expected to occur, but with an incremental increase in the number of new SCRs installed with the associated ammonia storage tanks and the number of existing SCRs upgraded, and replacements of existing burners with ULNBs.

For this reason, the incremental changes associated with implementing the proposed project will not be expected to alter the previous conclusions reached in the December 2015 Final PEA for NOx RECLAIM for the environmental topic areas which were identified as having no impacts (agriculture and forestry resources; biological resources; cultural and tribal cultural resources; geology and soils; land use and planning; mineral resources; population and housing; and recreation). Therefore, since no impacts to these environmental topic areas would occur if the proposed project implemented, they are not further evaluated in this SEA. A brief summary of the previous conclusions reached as well as the reasoning why the no impact conclusions would remain the same for the proposed project is provided for each of the aforementioned environmental topic areas.

Agriculture and Forestry

The December 2015 Final PEA for NOx RECLAIM previously analyzed agriculture and forestry impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS and concluded that no impacts would occur because none of the affected facilities are located near agricultural or forest areas. The proposed project is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded. Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs. The proposed project will affect the same nine refinery-sector facilities as previously analyzed in December 2015 Final PEA for NOx RECLAIM plus an additional seven refinery facilities. None of these 16 facilities are located near agricultural or forest areas. Therefore, the previous conclusion of no impact to agriculture and forestry resources reached in the December 2015 Final PEA for NOx RECLAIM will continue to apply to the proposed project.

Biological Resources

The December 2015 Final PEA for NOx RECLAIM previously analyzed biological resources impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS and concluded that no impacts would occur because these activities would occur inside the boundaries of industrial facilities which have been previously cleared of vegetation and have already been paved for safety and fire prevention reasons and as such, would not result in or have the potential to result in the removal of vegetation with potential to support wildlife. The proposed project will affect the same nine refinery-sector facilities as previously analyzed in December 2015 Final PEA for NOx RECLAIM plus an additional seven refinery facilities, which are also industrial facilities which have been previously cleared of vegetation and have already been paved for safety and fire prevention reasons. Thus, the proposed project would not be expected to result in or have the potential to result in the removal of vegetation with potential to support wildlife at these seven additional facilities or at the nine refinery facilities that were previously analyzed in December 2015 Final PEA for NOx RECLAIM. Therefore, the previous conclusion of no impact to biological resources reached in the December 2015 Final PEA for NOx RECLAIM will continue to apply to the proposed project.

Cultural and Tribal Cultural Resources

The December 2015 Final PEA for NOx RECLAIM previously analyzed cultural and tribal cultural resource impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS and concluded that no impacts would occur at any of the affected facilities since the construction-related activities are expected to be confined within the existing footprint of the affected facilities that have been fully developed and paved such that no physical changes to the environment which may disturb paleontological, archaeological, or historical resources would occur. For the same reason, the analysis in the December 2015 Final PEA for NOx RECLAIM also concluded that no site, feature, place, cultural landscape, sacred place or object with cultural value to a California Native American Tribe would be disturbed. The proposed project is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded. Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs. The proposed project will affect the same nine refinery-sector facilities as previously analyzed in December 2015 Final PEA for NOx RECLAIM plus an additional seven refinery facilities, which are also industrial facilities which are expected to be devoid of the same types of cultural and tribal cultural resources. Therefore, the previous conclusion of no impact to cultural and tribal cultural resource resources reached in the December 2015 Final PEA for NOx RECLAIM will continue to apply to the proposed project.

Geology and Soils

The December 2015 Final PEA for NOx RECLAIM previously analyzed geology and soils impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS and concluded that no impacts would occur because all of the affected facilities are located in developed industrial-zoned settings and:

1) relatively little site preparation involved with installation of add-on controls would not be expected to adversely affect geophysical conditions in the jurisdiction of the South Coast AQMD;
2) installation of add-on controls was expected to conform to stringent requirements in the Uniform Building Code and all other applicable state and local building codes, which consider seismic design requirements and liquefaction potential for constructing foundations in areas potentially subject to liquefaction;
3) installation of add-on controls would require no alteration to the exposure of people or property to geological hazards such as earthquakes, landslides, mudslides, ground failure, or other natural hazards would occur;
4) installation of add-on controls would not cause a substantial exposure of people or structures to the risk of loss, injury, or death involving the rupture of an earthquake fault, seismic ground shaking, ground failure or landslides;
5) installation of add-on controls would not expose people or property to new impacts related to expansive soils or soils incapable of supporting water disposal; and
6) all of the affected facilities have existing wastewater treatment systems so no soil changes associated with the installation of septic tanks or alternative wastewater disposal system would occur;

The proposed project is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded. Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs. The proposed project will affect the same nine refinery-sector facilities as previously analyzed in December 2015 Final PEA for NOx RECLAIM plus an additional seven refinery facilities which are also located in developed industrial-zoned settings. The same reasoning for why no geological and soils impacts would occur as listed in items 1) through 6) also apply to the proposed project.

Therefore, the previous conclusion of no impact to geology and soils reached in the December 2015 Final PEA for NOx RECLAIM will continue to apply to the proposed project.

Land Use and Planning

The December 2015 Final PEA for NOx RECLAIM previously analyzed land use and planning impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS and concluded that no impacts to present or planned land uses in the region would occur because:

1) all of the construction activities are expected to occur within the confines of the existing facilities;
2) installation of add-on controls would not affect habitat conservation or natural community conservation plans, agricultural resources or operations;
3) installation of add-on controls would not divide existing communities; and
4) installation of add-on controls would not require new development or alterations to existing land designations.

The proposed project is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded. Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs. The proposed project will affect the same nine refinery-sector facilities as previously analyzed in December 2015 Final PEA for NOx RECLAIM plus an additional seven refinery facilities. The same reasoning for why no land use and planning impacts would occur as listed in items 1) through 4) also apply to the proposed project. Therefore, the previous conclusion of no impact to land use and planning impacts reached in the December 2015 Final PEA for NOx RECLAIM will continue to apply to the proposed project.

Mineral Resources

The December 2015 Final PEA for NOx RECLAIM previously analyzed mineral resources impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS and concluded that no impacts would occur because the installation of add-on controls would not result in the loss of availability of a known mineral resource of value to the region and the residents of the state such as aggregate, coal, clay, shale, et cetera, or of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.

The proposed project is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded. Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs. The proposed project will affect the same nine refinery-sector facilities as previously analyzed in December 2015 Final PEA for NOx RECLAIM plus an additional seven refinery facilities. Consistent with the previous conclusion, installation of add-on controls at all 16 facilities as part of the proposed project would also not result in the loss of availability of a known mineral resource of value to the region and the residents of the state such as aggregate, coal, clay, shale, et cetera, or of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.

Therefore, the previous conclusion of no impact to mineral resources reached in the December 2015 Final PEA for NOx RECLAIM will continue to apply to the proposed project.

Population and Housing

The December 2015 Final PEA for NOx RECLAIM previously analyzed population and housing impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS and concluded that no impacts would occur because the installation of add-on controls would not:

1) require construction workers to permanently relocate or require new housing or commercial facilities to be built;
2) change the distribution of the population;
3) result in the creation of any new industry that would affect population growth, directly or indirectly by inducing the construction of single- or multiple-family units; and
4) require the displacement of people or housing elsewhere in the South Coast AQMD jurisdiction.

The proposed project is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded. Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs. The proposed project will affect the same nine refinery-sector facilities as previously analyzed in December 2015 Final PEA for NOx RECLAIM plus an additional seven refinery facilities. Consistent with the previous conclusion, installation of add-on controls at all 16 facilities as part of the proposed project would also not result in the impacts summarized in items 1) through 4). Therefore, the previous conclusion of no impact to population and housing reached in the December 2015 Final PEA for NOx RECLAIM will continue to apply to the proposed project.

Recreation

The December 2015 Final PEA for NOx RECLAIM previously analyzed recreation impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS and concluded that no impacts would occur because the installation of add-on controls would not:

1) directly or indirectly increase or redistribute population;
2) affect or increase the demand for or use of existing neighborhood and regional parks or other recreational facilities; and
3) require the construction of new or the expansion of existing recreational facilities that might have an adverse physical effects on the environment.

The proposed project is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded. Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs. The proposed project will affect the same nine refinery-sector facilities as previously analyzed in December 2015 Final PEA for NOx RECLAIM plus an additional seven refinery facilities. Consistent with the previous conclusion, installation of add-on controls at all 16 facilities as part of the proposed project would also not result in the impacts summarized in items 1) through 3). Therefore, the previous conclusion of no impact to recreation reached in the December 2015 Final PEA for NOx RECLAIM will continue to apply to the proposed project.

At the time the NOP/IS for the Draft PEA for NOx RECLAIM was circulated for public review and public comment and after the December 2015 Final PEA for NOx RECLAIM was certified, the environmental checklist did not include wildfires as an environmental topic area to be evaluated. However, in 2019, the CEQA Guidelines added a new topic of wildfires to the environmental checklist. To make the analysis of environmental impacts consistent with the recent changes to the environmental checklist, Table 4.5-1 provides the new environmental checklist questions for the topic of wildfires and an analysis of whether the proposed project would be expected to contribute to wildfire impacts.

Table 4.5-1
Evaluation of Wildfire Impacts

WILDFIRE: If located in or near state responsibility areas or lands classified as very high fire hazard severity zones, would the project:	**ANALYSIS AND CONCLUSION**
a) Substantially impair an adopted emergency response plan or emergency evacuation plan?	**No Impact.** None of the affected facilities are located in or near state responsibility areas or lands classified as very high fire hazard severity zones. In the NOP/IS for the Draft PEA for NOx RECLAIM, the response to question f) in Section VIII – Hazards and Hazardous Materials, poses the same question and the analysis concluded that the project analyzed in December 2015 Final PEA for NOx RECLAIM would have no impact on any adopted emergency response plan or emergency evacuation plan. Thus, implementation of the proposed project would also not be expected to substantially impair an adopted emergency response plan or emergency evacuation plan.

Table 4.5-1 (continued)
Evaluation of Wildfire Impacts

WILDFIRE: If located in or near state responsibility areas or lands classified as very high fire hazard severity zones, would the project:	**ANALYSIS AND CONCLUSION**
b) Due to slope, prevailing winds, and other factors, exacerbate wildfire risks, and thereby expose project occupants to, pollutant concentrations from a wildfire or the uncontrolled spread of a wildfire?	**No Impact.** None of the affected facilities are located in or near state responsibility areas or lands classified as very high fire hazard severity zones. The facilities subject to the proposed project are located in established industrial areas which are not near wildlands. In the event of a wildfire, no exacerbation of wildfire risks, and no consequential exposure of the project occupants to pollutant concentrations from a wildfire or the uncontrolled spread of a wildfire due to slope, prevailing winds, or other factors would be expected to occur.
c) Require the installation or maintenance of associated infrastructure (such as roads, fuel breaks, emergency water sources, power lines or other utilities) that may exacerbate fire risk or that may result in temporary or ongoing impacts to the environment?	**No Impact.** None of the affected facilities are located in or near state responsibility areas or lands classified as very high fire hazard severity zones. Also, because the proposed project does not require any construction beyond existing facility boundaries, the installation or maintenance of associated infrastructure (such as roads, fuel breaks, emergency water sources, power lines, or other utilities) that may exacerbate fire risk or that may result in temporary or ongoing impacts to the environment are not required and would not be expected to occur.

Table 4.5-1 (concluded)
Evaluation of Wildfire Impacts

WILDFIRE: If located in or near state responsibility areas or lands classified as very high fire hazard severity zones, would the project:	**ANALYSIS AND CONCLUSION**
d) Expose people or structures to significant risks, including downslope or downstream flooding or landslides, as a result of runoff, post-fire slope instability, or drainage changes?	**No Impact.** None of the affected facilities are located in or near state responsibility areas or lands classified as very high fire hazard severity zones. In the NOP/IS for the Draft PEA for NOx RECLAIM, the response to question c) in Section VII – Geology and Soils, poses a similar question relative to landslides and the analysis concluded that the project analyzed in December 2015 Final PEA for NOx RECLAIM would have no impact. Also, In the NOP/IS for the Draft PEA for NOx RECLAIM, the response to question f) in Section IX – Hydrology and Water Quality, poses a similar question relative to flooding and the analysis concluded that the project analyzed in December 2015 Final PEA for NOx RECLAIM would have no impact. Thus, implementation of the proposed project would also not be expected to expose people or structures to new significant risks, including downslope or downstream flooding or landslides, as a result of runoff, post-fire slope instability, or drainage changes.
e) Expose people or structures, either directly or indirectly, to a significant risk of loss, injury or death involving wildfires?	**No Impact.** None of the affected facilities are located in or near state responsibility areas or lands classified as very high fire hazard severity zones. In the NOP/IS for the Draft PEA for NOx RECLAIM, the response to question g) in Section VIII – Hazards and Hazardous Materials, poses essentially the same question and the analysis concluded that the project analyzed in December 2015 Final PEA for NOx RECLAIM would not expose people or structures to a significant risk of loss, injury or death involving wildland fires, including where wildlands are adjacent to urbanized areas or where residences are intermixed with wildlands. Thus, implementation of the proposed project would also not be expected to expose people or structures, either directly or indirectly, to a significant risk of loss, injury or death involving wildfires.

Based on the analysis presented in Table 4.5-1, the proposed project would be expected to have no impacts on wildfires.

Environmental Topic Areas Previously Concluded In The NOP/IS for the December 2015 Final PEA for NOx RECLAIM To Have Less Than Significant Impacts

The following environmental topic areas were previously evaluated in the NOP/IS for the Draft PEA for NOx RECLAIM and were concluded in the December 2015 Final PEA for NOx RECLAIM to have less than significant impacts: noise and public services.

This SEA independently considers the currently proposed project and analyzes the incremental changes, if any, relative to the baseline which is the project analyzed in the December 2015 Final PEA for NOx RECLAIM. While seven additional facilities and additional equipment categories will apply to the proposed project when compared to the project analyzed in December 2015 Final PEA for NOx RECLAIM for the nine refinery-sector facilities, the same types of air pollution control equipment with similar impacts to the same environmental topic areas that were previously analyzed are expected to occur, but with an incremental increase in the number of new SCRs installed with the associated ammonia storage tanks and the number of existing SCRs upgraded, and replacements of existing burners with ULNBs.

For this reason, the incremental changes associated with implementing the proposed project will not be expected to alter the previous conclusions reached in the December 2015 Final PEA for NOx RECLAIM for the environmental topic areas which were identified as having less than significant impacts (noise and public services). Therefore, since less than significant impacts to these environmental topic areas would occur if the proposed project implemented, they are not further evaluated in this SEA. A brief summary of the previous conclusions reached as well as the reasoning why the less than significant impact conclusions would remain the same for the proposed project is provided for each of these aforementioned environmental topic areas.

Noise

The December 2015 Final PEA for NOx RECLAIM previously analyzed noise impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS and concluded that less than significant impacts would occur because:

1) all of the construction activities associating with installation of add-on controls are expected to occur within the confines of the existing facilities where the existing noise environment at each of the affected facilities is typically dominated by noise from existing equipment onsite, vehicular traffic around the facilities, and trucks entering and exiting facility premises;
2) while additional noise associated with the use of construction equipment and construction-related traffic would be expected to occur, it would not be in excess of current operations at each of the existing facilities;
3) once operational, the new or modified NOx control devices are not typically equipment that generate substantial amounts of noise but if additional noise is generated, each facility will be required to comply with all existing noise control laws or ordinances, including noise standards established by OSHA and Cal/OSHA to protect worker health; and
4) the addition of new or modification of existing NOx control equipment would not expose people residing or working in the project area to the same degree of excessive noise levels associated with airplanes, even though some of the affected facilities project are located at sites within an airport land use plan, or within two miles of a public airport.

The proposed project is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded. Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs. The proposed project will affect the same nine refinery-sector facilities as previously analyzed in December 2015 Final PEA for NOx RECLAIM plus an additional seven refinery facilities which are also located in developed industrial-zoned settings. The same reasoning for why less than significant noise impacts would occur as listed in items 1) through 4) also apply to the proposed project. Therefore, the previous conclusion of less than significant noise impacts reached in the December 2015 Final PEA for NOx RECLAIM will continue to apply to the proposed project.

Public Services

The December 2015 Final PEA for NOx RECLAIM previously analyzed public services impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS and concluded that less than significant impacts would occur because:

1) the installation of add-on controls may require the use of hazardous materials and an accidental or emergency release of hazardous materials, while unpredictable and with a low probability of occurring, would require the assistance of public services personnel;
2) police and fire department personnel may be needed since they are typically first responders to emergency situations and may assist local hazmat teams with containing hazardous materials, putting out fires, and controlling crowds to reduce public exposure to releases of hazardous materials in the event of a spill;
3) emergency or rescue vehicles operated by local, state, and federal law enforcement agencies, police and sheriff departments, fire departments, hospitals, medical or paramedic facilities, that are used for responding to situations where potential threats to life or property exist, including, but not limited to fire, ambulance calls, or life-saving calls, may be needed in the event of an accidental release or other emergency
4) all of the affected facilities have existing emergency response plans so any changes to those plans would not be expected to dramatically alter how emergency personnel would respond to an accidental release or other emergency

The proposed project is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded. Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs. The proposed project will affect the same nine refinery-sector facilities as previously analyzed in December 2015 Final PEA for NOx RECLAIM plus an additional seven refinery facilities which are also located in developed industrial-zoned settings. The same reasoning for why less than significant public service impacts relating to fire and police protection services would occur as listed in items 1) through 4) also apply to the proposed project.

The analysis in the December 2015 Final PEA for NOx RECLAIM also concluded no impacts to public services from schools and other facilities because installation of add-on controls would not cause an increase in the local population such that:

1) additional personnel at local schools and parks would not be needed
2) other types of government services, except for permitting the equipment or altering permit conditions by the South Coast AQMD personnel, would not be needed; and
3) no new or physically altered government facilities would be needed in order to maintain acceptable service ratios, response times, or other performance objectives.

The same reasoning for why no significant public service impacts relating to schools and other facilities would occur as listed in items 1) through 3) also apply to the proposed project. Therefore, the previous conclusion of less than significant public services impacts relating to fire and police protection services and the no impacts conclusion relating to schools and other facilities reached in the December 2015 Final PEA for NOx RECLAIM will continue to apply to the proposed project.

Environmental Topic Areas Previously Concluded In The December 2015 Final PEA for NOx RECLAIM To Have Less Than Significant Impacts

In addition, the NOP/IS for the Draft PEA for NOx RECLAIM identified aesthetics, air quality and GHGs, energy, hydrology and water quality, solid and hazardous waste, and transportation and traffic as requiring further analyses in the Draft PEA. The final analysis in the December 2015 Final PEA for NOx RECLAIM concluded less than significant impacts for the following environmental topic areas: aesthetics, air quality during operation, energy, water quality, solid and hazardous waste, and transportation and traffic. The following discussion independently considers the currently proposed project and analyzes the incremental changes, if any, relative to the baseline which is the project analyzed in the December 2015 Final PEA for NOx RECLAIM, in order to determine if the previous conclusions of less than significant impacts for the environmental topic areas of aesthetics, air quality during operation, energy, water quality, solid and hazardous waste, and transportation and traffic need to be changed.

Aesthetics

The December 2015 Final PEA for NOx RECLAIM previously analyzed aesthetics impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS.

The proposed project is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded. The previous analysis determined that, while construction equipment will be needed, the majority of the construction equipment is expected to be low in height and not substantially visible to the surrounding area due to existing fencing along the property lines and existing structures currently within the facilities that would buffer the views of the construction activities. Even if construction equipment, such as a crane, may be visible, because each affected facility is located in heavy industrial areas, the construction equipment is not expected to be substantially discernable from what exists on-site for routine operations and maintenance activities. Further, the construction activities are not expected to adversely impact views and aesthetics resources since most of the heavy equipment and activities are expected to occur within the confines of each existing facility and are expected to introduce only minor visual changes to areas outside each facility, if at all, depending on the location of the construction activities within the facility. Lastly, the construction activities are expected to be temporary in nature and will cease following completion of the equipment installation or modifications. After construction is completed, all construction equipment will be removed.

Increasing the number of SCRs that will installed and upgraded at more facilities as part of the proposed project will not change the previous aesthetics analysis or the conclusion of less than significant aesthetics impacts for construction since the same construction equipment and activities as previously analyzed in the December 2015 Final PEA for NOx RECLAIM would be expected to occur.

Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs. The replacement of burners with ULNBs involves removing the housing to be able to access the internal components of the combustion unit, including the burners, which are located in a confined area. As such, the construction equipment that may be needed for replacing existing burners with ULNBs is projected to be fewer, much smaller in size, and used for a shorter duration than what would be required for installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS. Thus, the aesthetics impacts during construction for installation of ULNBs is expected to be less severe than the previously analyzed aesthetics impacts for installations of the other, larger NOx control technologies.

Overall, the proposed project would be expected to have less than significant impacts during construction. Thus, no changes to the conclusion for aesthetics during construction are needed.

The previous analysis in the December 2015 Final PEA for NOx RECLAIM also concluded less than significant aesthetics impacts during operation because SCRs, Ultracat™ DGSs, and LoTOx™ technology without a WGS, if installed (or modified) and operated, would be expected to blend in with the existing industrial profile at the affected facilities because the heights of these units are typically smaller when compared to neighboring existing equipment onsite at a refinery and their associated stack heights would be about the same or shorter than existing stacks within the affected facilities.

Even though the proposed project will have an incremental increase in the number of SCRs installed and upgraded, the operational aesthetics impacts are expected to remain the same as the previous analysis and less than significant. Further since burners are internal components of existing combustion equipment, the after the ULNBs are installed, they will not be visible within or outside of each facility's property boundaries. Overall, the proposed project would be expected to have less than significant impacts during operation. Thus, no changes to the conclusion for aesthetics during operation are needed.

Air Quality During Operation
The December 2015 Final PEA for NOx RECLAIM previously concluded that air quality impacts during operation would be less than significant due to achieving NOx emission reductions from affected facilities either surrendering NOx RTCs or making the facility-specific modifications to install new SCRs with associated ammonia storage tanks, upgrade existing SCRs, install new LoTOx™ with and without WGSs, and install new UltraCat™ with DGS.

The proposed project is expected to result in an overall NOx emission reductions of 7 to 8 tons per day which is expected to result from affected facilities making the same types of facility-specific modifications as previously analyzed in the December 2015 Final PEA for NOx RECLAIM, but with an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded. Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs.

Section 4.2 of this SEA analyzes the proposed project's air quality impacts during operation and concludes less than significant operational air quality impacts since the overall projected NOx emission reductions are an air quality benefit.

Energy
The December 2015 Final PEA for NOx RECLAIM previously analyzed energy impacts associated with use of diesel fuel and gasoline in mobile sources as part of construction and operation activities associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS. The December 2015 Final PEA for NOx RECLAIM also previously analyzed energy impacts associated with use of electricity to operate the NOx controls once they were installed.

The analysis in the December 2015 Final PEA for NOx RECLAIM concluded that the projected increased usages of diesel fuel and gasoline during construction and operation would not create: 1) any significant effects on local or regional energy supplies and on requirements for additional energy; and 2) any significant effects on peak and base period demands on the availability of diesel fuel and gasoline. Similarly, the analysis in the December 2015 Final PEA for NOx RECLAIM concluded that the projected increased usage of electricity would cause less than significant energy impacts because: 1) the amount of electricity needed would not exceed the South Coast AQMD's energy threshold of one percent of supply; 2) any usage of electricity during operation would not be expected to result in the need for new or substantially altered power utility systems; 3) any operational increases in electricity usage that may occur would not be expected to create any significant effects on local or regional electricity supplies or on requirements for additional electricity; and 4) any increased operational usage of electricity that may occur would not be expected to create any significant effects on peak and base period demands for electricity.

The proposed project is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded. Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs.

Of these incremental changes, additional diesel fuel and gasoline will be needed during construction of the additional new SCRs and associated ammonia storage tanks and the installation of ULNBs. Operation of the additional new SCRs and associated ammonia storage tanks will require electricity for their operation as well as additional diesel fuel for vehicles that deliver ammonia and fresh catalyst and haul away spent catalyst. Operation of ULNBs, however, do not utilize electricity, ammonia or catalyst, so no additional electricity, diesel fuel or gasoline would be needed during operation of ULNBs.

The analysis of additional electricity, diesel and gasoline fuel that may be needed to address the incremental increases that may occur during construction and operation are included in Appendix C of this SEA. Because the incremental increase in the projected use of electricity, diesel fuel and gasoline for the proposed project is not substantial, the overall conclusions of less than significant energy impacts associated with the increase use of electricity, diesel fuel and gasoline would not change.

While the proposed project is expected to have more severe energy impacts than what was previously analyzed in the December 2015 Final PEA for NOx RECLAIM [CEQA Guidelines Section 15162(a)(3)(B)], the incremental energy impacts from the proposed project do not make the previous energy impacts significant. Thus, no change to the overall less than significant conclusion of energy impacts is needed if the proposed project is implemented.

Water Quality

The December 2015 Final PEA for NOx RECLAIM previously analyzed the construction and operational water quality impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS.

Water quality impacts associated with suppressing fugitive dust during construction of all of the potential NOx controls as well as hydrotesting the new ammonia storage tanks post-construction were concluded in the December 2015 Final PEA for NOx RECLAIM to be less than significant because the water gets absorbed into the soil such that no wastewater is generated that would create adverse water quality impacts. Similarly, of the potential NOx controls that were evaluated in the December 2015 Final PEA for NOx RECLAIM, only LoTOx™ with WGSs was identified as utilizing water during operation and in turn, generating wastewater that would create potential water quality impacts. Nonetheless, the analysis in the December 2015 Final PEA for NOx RECLAIM concluded less than significant water quality impacts associated with operating LoTOx™ with WGSs.

The proposed project is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded. Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs. Foundation work that would disturb soil is neither needed for upgrading existing SCRs nor replacing burners with ULNBs inside existing combustion equipment. During construction, only the installation of new SCRs and associated ammonia storage tanks could involve soil disturbance activities requiring water for fugitive dust suppression purposes. Again, since the water used for fugitive dust suppression purposes gets absorbed into the soil, no wastewater is generated that would create adverse water quality impacts. Since the proposed project will not be expected to create additional water quality impacts due to fugitive dust suppression activities, no change to the overall less than significant conclusion of construction water quality impacts for fugitive dust suppression purposes is needed if the proposed project is implemented.

The analysis in the December 2015 Final PEA for NOx RECLAIM concluded less than significant water quality impacts due to stormwater because the total amount of disturbed area at each of the affected facilities would be less than one acre which meant that a NPDES General Permit for Storm Water Discharges Associated with Construction Activity, also referred to as a Storm Water Construction Permit, would not be required. Because the proposed project is also expected to disturb substantially less than one acre per facility, a Storm Water Construction Permit would not be required. Since the proposed project will not be expected to create additional construction water quality impacts associated with stormwater, no change to the overall less than significant conclusion of construction water quality impacts for stormwater is needed if the proposed project is implemented.

The previous water quality analysis in the December 2015 Final PEA for NOx RECLAIM also specifically addressed the water quality impacts expected from wastewater generated from hydrotesting the new ammonia storage tanks and concluded less than significant water quality impacts for the following reasons: 1) any wastewater generated from hydrotesting or pressure testing was expected to flow to each affected facility's wastewater treatment or collection system and either be recycled or discharged after treatment with process wastewater such that no groundwater would be affected; and 2) hydrotesting would occur as a one-time event per ammonia storage tank and the volume of wastewater that will be generated would was relatively minimal and within the capacity of each facility's wastewater treatment and collection systems.

Since existing SCRs have existing ammonia tanks, any upgrades to existing SCRs will not require hydrotesting of the existing ammonia tanks. Similarly, ULNBs do not utilize ammonia, so no new ammonia storage tanks would be installed if existing burners are replaced with ULNBs. Thus, the proposed project will be expected to have an incremental increase in the number of ammonia storage tanks that will be installed for new SCRs only, which means more hydrotesting will be needed. However, all of the affected facilities subject to the proposed project have existing wastewater treatment or collection systems that are capable of recycling or discharging the water used for hydrotesting after treatment with process wastewater such that no groundwater would be affected. As with the project analyzed in the December 2015 Final PEA for NOx RECLAIM, the incremental increase in hydrotesting would occur as a one-time event per ammonia storage tank and the volume of wastewater that will be generated will be the same for each tank, and would was relatively minimal and within the capacity of each facility's wastewater treatment and collection system. Since no additional water quality impacts due to wastewater generated from hydrotesting the additional new ammonia storage tanks is expected to occur if the proposed project is implemented, no change is needed to the previous conclusion of less than significant water quality impacts from wastewater generated due to hydrotesting.

The analysis in the December 2015 Final PEA for NOx RECLAIM concluded less than significant water quality impacts during operation which was based on each affected facility's wastewater discharge limit and each facility's estimated potential increase in wastewater that may result from operating NOx control equipment that utilize water (e.g., LoTOx™ with WGSs).

While the proposed project is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded, neither SCRs (new or upgraded) and the associated ammonia storage tanks nor ULNBs utilize water for their operation which means no operational wastewater would be generated. Since no incremental impacts to operational water quality is expected to occur as a result of the proposed project, no change to the previous conclusion of water quality impacts during operation is needed.

Solid and Hazardous Waste

The December 2015 Final PEA for NOx RECLAIM previously analyzed the construction solid and hazardous waste impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS. Demolition, site preparation, grading and excavating were construction activities identified as having the potential to generate construction-related solid waste such as demolition waste and excavated soils as result installing the aforementioned NOx control equipment. Construction-related waste was expected to be disposed of either at a Class II (industrial) or Class III (municipal) landfill, while demolished equipment could be dismantled and with the metals sold off as scrap. Any excavated soil would need to be characterized, treated, and disposed of offsite or reused in accordance with applicable regulations. The total amount of area that was estimated to be disturbed during construction was 2.44 acres for all 20 facilities; however, there was no direct correlation to the quantity of construction debris that may be generated based on the plot size of the area to be disturbed during construction. The analysis concluded that the potential amount of construction debris generated would not be expected to exceed the designated capacity of the landfills that serve the Southern California area., even though the actual amount of construction debris could not be calculated. For this reason, the analysis concluded less than significant impacts relative to the amount of waste expected to be generated during construction.

The December 2015 Final PEA for NOx RECLAIM also previously analyzed the solid and hazardous waste impacts associated with spent catalyst generated as part of operating SCRs, LoTOx™ with and without WGSs, and UltraCat™ with DGS. The analysis concluded that the none of spent catalyst would be disposed of as solid waste because all of affected facilities currently handling spent catalyst indicated that they would continue to haul it to a local cement manufacturing facility for recycling in lieu of disposal. For this reason, the analysis concluded less than significant solid and hazardous waste impacts during operation.

The proposed project is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded. Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs. Since existing SCRs have existing ammonia tanks, and since ULNBs are internal components of existing combustion equipment, demolition and site preparation activities may only be needed for the installation of new SCRs with associated ammonia storage tanks. Similar to the analysis in the December 2015 Final PEA for NOx RECLAIM, unquantifiable amounts of solid waste comprised of construction debris such as demolition waste and contaminated soils are expected to occur. Construction-related can continue to be disposed of either at a Class II (industrial) or Class III (municipal) landfill, while demolished equipment to make room for the new SCRs and new ammonia storage tanks could be dismantled and with the metals sold off as scrap. Any excavated soil would need to be characterized, treated, and disposed of offsite or reused in accordance with applicable regulations. The incremental amount of area that is estimated to be disturbed during construction is 0.34 acre, which is less severe than what was previously analyzed in the December 2015 Final PEA for NOx RECLAIM. While there is no direct correlation to the quantity of construction debris that may be generated based on the plot size, the relatively small amount of debris that may be generated would not be expected to exceed the designated capacity of the landfills that serve the Southern California area. Thus, no change to the previous conclusion of less than significant solid and hazardous waste impacts is needed if the proposed project is implemented.

For the proposed project, incremental increases in operational waste are expected to be generated from replacing spent catalyst in the SCRs with fresh catalyst. The same facilities that were analyzed in the December 2015 Final PEA for NOx RECLAIM, will be expected to have an incremental increase in the amount of spent catalyst generated from SCRs as a result of the proposed project, and these facilities are expected to continue their current practice of haul the spent catalyst to a local cement manufacturing facility for recycling in lieu of disposal. For this reason, the proposed project is expected to have less than significant solid and hazardous waste impacts during operation. Thus, no change to the overall less than significant conclusion of solid and hazardous waste impacts during construction and operation is needed if the proposed project is implemented.

Transportation and Traffic

The December 2015 Final PEA for NOx RECLAIM previously analyzed the construction and operational transportation and traffic impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS and concluded less than significant transportation and traffic impacts relative to: 1) the peak daily work force that would be needed during construction and their associated trips; 2) peak daily number of heavy-duty truck trips during construction; and 3) peak daily number of heavy-duty truck trips during operation.

The proposed project is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded. Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs. Relative to the topic of transportation and traffic, additional construction workers and their associated trips may be needed to accommodate the additional construction needed to install the additional new SCRS and associated ammonia storage tanks, upgrade additional existing SCRs, and install new ULNBs. Similarly, due to the additional new SCRs and associated ammonia storage tanks that will be operating, additional trips to deliver ammonia and fresh catalyst and haul away spent catalyst is expected. The analysis of additional trips that may be needed to address the incremental increases that may occur during construction and operation are included in Appendix C of this SEA.

While implementing the proposed project is expected to result in incremental increases in the number of trips that may occur during construction and operation, the increases do not exceed the significance criteria for transportation and traffic. Therefore, the overall conclusions of less than significant transportation and traffic impacts during construction and operation would not be expected to change.

Based on the foregoing analysis, the incremental effects of the proposed project for environmental topic areas of aesthetics, air quality during operation, energy, water quality, solid and hazardous waste, and transportation and traffic indicated that no change to the less than significant conclusions previously reached in December 2015 Final PEA for NOx RECLAIM is needed.

4.6 SIGNIFICANT ENVIRONMENTAL EFFECTS WHICH CANNOT BE AVOIDED

CEQA Guidelines Section 15126(c) requires an environmental analysis to consider "any significant irreversible environmental changes which would be involved if the proposed action should be implemented."

The December 2015 Final PEA for NOx RECLAIM previously analyzed the construction and operational impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCat™ with DGS. The topics of air quality during construction, GHGs and hydrology (water demand associated with the operation of LoTOx™ with WGSs) were identified in the December 2015 Final PEA for NOx RECLAIM as having significant environmental effects which cannot be avoided for the following reasons: 1) the timing and extent of construction that may occur concurrently at multiple facilities on a peak day was unknown and unable to be predicted, so construction air quality impacts on a peak day were concluded to be significant; 2) once the NOx controls were installed and operational, the GHG emissions associated from electricity use, water conveyance, wastewater conveyance, and operational truck trips would be significant for the lifetime of the equipment; 3) the potential amount of water that would be needed to operate multiple LoTOx™ with WGSs would be needed for the lifetime of the equipment.

The proposed project, as evaluated in this SEA, is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed and the number of existing SCRs to be upgraded. Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs. Incremental changes that may result from implementing the proposed project are expected to contribute to the previous conclusions in the December 2015 Final PEA for NOx RECLAIM of significant adverse air quality impacts during construction, and significant GHG impacts. However, operating additional SCRs and ULNBs do not contribute to the previously analyzed portion of GHG impacts attributed to water conveyance and wastewater conveyance.

When the impacts from the December 2015 Final PEA for NOx RECLAIM and this SEA are considered together, the topics of air quality during construction, GHGs and hydrology (water demand associated with the operation of LoTOx™ with WGSs) will be expected to have significant environmental effects which cannot be avoided.

4.7 POTENTIAL GROWTH-INDUCING IMPACTS

CEQA Guidelines Section 15126(d) requires an environmental analysis to consider the "growth-inducing impact of the proposed action." CEQA defines growth-inducing impacts as those impacts of a proposed project that "could foster economic or population growth, or the construction of additional housing, either directly or indirectly, in the surrounding environment. Included in this are projects, which would remove obstacles to population growth." [CEQA Guidelines Section 15126.2(d)].

To address this issue, potential growth-inducing effects are examined through the following considerations:

- Facilitation of economic effects that could result in other activities that could significantly affect the environment;
- Expansion requirements for one or more public services to maintain desired levels of service as a result of the proposed project;
- Removal of obstacles to growth through the construction or extension of major infrastructure facilities that do not presently exist in the project area or through changes in existing regulations pertaining to land development;
- Adding development or encroachment into open space; and/or
- Setting a precedent that could encourage and facilitate other activities that could significantly affect the environment.

4.7.1 Economic and Population Growth, and Related Public Services

A project would be considered to directly induce growth if it would directly foster economic or population growth or the construction of new housing in the surrounding environment (e.g., if it would remove an obstacle to growth by expanding existing infrastructure such as new roads or wastewater treatment plants).

The project evaluated in the December 2015 Final PEA for NOx RECLAIM was concluded to not remove barriers to population growth, since implementation of the NOx RECLAIM program involved no changes to a General Plan, zoning ordinance, or a related land use policy.

The proposed project evaluated in this SEA contains incremental changes to the project previously evaluated in the December 2015 Final PEA for NOx RECLAIM. The proposed project would also not be expected to remove barriers to population growth, since implementation of the proposed project does not involve any changes to a General Plan, zoning ordinance, or a related land use policy.

Further, the proposed project, as with the project evaluated in the December 2015 Final PEA for NOx RECLAIM, does not include policies that would encourage the development of new housing or population-generating uses or infrastructure that would directly encourage such uses. The proposed project, as with the project evaluated in the December 2015 Final PEA for NOx RECLAIM, may indirectly increase the efficiency of the region's urban form through encouraging more air quality efficient development patterns in the form of NOx emission reductions, but this would not increase or facilitate population growth. The proposed project, as with the project evaluated in the December 2015 Final PEA for NOx RECLAIM, does not change jurisdictional authority or responsibility concerning land use or property issues. Land use authority falls solely under the purview of the local governments. The South Coast AQMD is specifically excluded from infringing on existing city or county land use authority (California Health and Safety Code Section 40414). Therefore, the proposed project would not directly trigger new residential development in the area.

The proposed project may result in construction activities associated with installing new or modifying existing air pollution control equipment to achieve NOx reductions. However, the proposed project would not directly or indirectly stimulate substantial population growth, remove obstacles to population growth, or necessitate the construction of new community facilities that would lead to additional growth in the Basin. It is expected that construction workers will be largely drawn from the existing workforce pool in southern California. Considering the existing labor force of about 8.5 million in the region and current unemployment rate of about six percent, it is expected that a sufficient number of workers are available locally and that few or no workers would relocate for construction jobs potentially created by the proposed project as construction activities would be spread over a period from 2015 to 2022[29]. Further, the proposed project would not be expected to result in an increase in local population, housing, or associated public services (e.g., fire, police, schools, recreation, and library facilities) since no increase in population or the permanent number of workers is expected. Likewise, the proposed project would not create new demand for secondary services, including regional or specialty retail, restaurant or food delivery, recreation, or entertainment uses. As such, the proposed project would not foster economic or population growth in the surrounding area in a manner that would be growth-inducing.

Thus, implementing the proposed project will not, by itself, have any direct or indirect growth-inducing impacts on businesses in the South Coast AQMD's jurisdiction because it is not expected to foster economic or population growth or the construction of additional housing and primarily affects existing facilities.

4.7.2 Removal of Obstacles to Growth

The facilities that may be affected by the proposed project are located within an existing urbanized area. The proposed project would not employ activities or uses that would result in growth inducement, such as the development of new infrastructure (e.g., new roadway access or utilities) that would directly or indirectly cause the growth of new populations, communities, or currently undeveloped areas. The proposed project would require additional energy (electricity, diesel, gasoline, and natural gas) to implement but the increased energy requirements are expected to be within those projected for existing population growth of the region. While construction and operation activities that may occur as a result of the proposed project will require trips associated with construction workers, delivery of supplies and haul trips, the trips are expected to occur via existing roadways and transportation corridors. Thus, the proposed project is not expected to require the development of new roads or freeways. Likewise, the proposed project would not result

[29] EDD, Labor Market Information Division, California Labor Market Current Status, May/June 2015. http://www.labormarketinfo.edd.ca.gov/county/sbern.html#URLF

in an expansion of existing public service facilities (e.g., police, fire, libraries, and schools) or the development of public service facilities that do not already exist.

4.7.3 Development or Encroachments into Open Space

Development can be considered growth-inducing when it is not contiguous to existing urban development and introduces development into open space areas. The proposed project is situated within the existing South Coast Air Basin, which is urbanized. The areas of the Basin where construction activities may occur would be at existing stationary sources and the associated trips would occur along existing transportation corridors. Stationary sources are generally located within commercial and industrial (urbanized) areas. Any related construction activities would be expected to be within the confines of the existing facilities and would not encroach into open space. Therefore, the proposed project would not result in development within or encroachment into an open space area.

4.7.4 Precedent Setting Action

The 2016 AQMP recognized that many of the RECLAIM program's original advantages were diminishing, and in control measure CMB-05 – Further NOx Reductions from RECLAIM Assessment, committed to achieving NOx emission reductions of five tons per day by 2025, along with achieving BARCT level equivalency for all facilities through a command-and-control regulatory structure, while alleviating facilities from installing technology that could quickly become obsolete or only serve as an intermediate technology. In addition, AB 617, which was approved by the Governor, addresses nonvehicular air pollution including NOx; it requires air districts to implement BARCT no later than December 31, 2023, prioritizing permitted units that have not modified emissions-related permit conditions for the greatest period of time. Therefore, the proposed project is being prepared to comply with state and federal air quality planning regulations and requirements. This proposed project would not result in precedent-setting actions that might cause other significant environmental impacts (other than those already evaluated in the December 2015 Final PEA for NOx RECLAIM).

4.7.5 Conclusion

The proposed project was developed to comply with local, state and federal air quality planning requirements and is not expected to foster economic or population growth or result in the construction of additional housing or other infrastructure, either directly or indirectly, that would further encourage growth. While the proposed project could result in construction projects at existing stationary sources, the proposed project would not be considered growth-inducing, because it would not result in an increase in production of resources or cause a progression of growth that could significantly affect the environment either individually or cumulatively.

4.8 RELATIONSHIP BETWEEN SHORT-TERM AND LONG-TERM ENVIRONMENTAL GOALS

CEQA documents are required to explain and make findings about the relationship between short-term uses and long-term productivity. [CEQA Guidelines Section 15065(a)(2)]. An important consideration when analyzing the effects of a proposed project is whether it will result in short-term environmental benefits to the detriment of achieving long-term goals or maximizing productivity of these resources. Implementing the proposed project is not expected to achieve short-term goals at the expense of long-term environmental productivity or goal achievement. The objectives of the proposed project are to: 1) reduce NOx emissions from refinery equipment and transition equipment that is currently permitted under the NOx RECLAIM program to a command-and-control regulatory structure; 2) implement Control Measure CMB-05 by requiring affected equipment operating at RECLAIM or former RECLAIM facilities to comply with current BARCT in accordance with an implementation schedule for transitioning affected units at NOx RECLAIM facilities to a command-and-control regulatory structure; and 3) comply with the BARCT requirements in accordance with AB 617. By achieving additional reductions in NOx, an ozone and PM2.5 precursor, the proposed project will help attain federal and state air quality standards which are expected to enhance short and long-term environmental productivity in the region.

Implementing the proposed project does not narrow the range of beneficial uses of the environment. Of the potential environmental impacts discussed in Chapter 4, only those related to air quality during construction and GHG impacts, hazards and hazardous materials due to ammonia, and hydrology (water demand) are considered potentially significant. Implementation of recommended mitigation measures will ensure such impacts are mitigated to the greatest extent feasible.

CHAPTER 5

ALTERNATIVES

5.0 INTRODUCTION

This SEA provides a discussion of alternatives to the proposed project as required by CEQA. The alternatives discussion includes measures for attaining the objectives of the proposed project and provide a means for evaluating the comparative merits of each alternative. A 'no project' alternative must also be evaluated. The range of alternatives must be sufficient to permit a reasoned choice, but need not include every conceivable project alternative. CEQA Guidelines Section 15126.6(c) specifically notes that the range of alternatives required in a CEQA document is governed by a 'rule of reason' and only necessitates that the CEQA document set forth those alternatives necessary to permit a reasoned choice. The key issue is whether the selection and discussion of alternatives fosters informed decision making and public participation. A CEQA document need not consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative. In addition, South Coast AQMD's certified regulatory program pursuant to Public Resources Code Section 21080.5, CEQA Guidelines Section 15125(l), and South Coast AQMD Rule 110 does not impose any greater requirements for a discussion of project alternatives in a SEA than is required for an EIR under CEQA.

5.1 METHODOLOGY FOR DEVELOPING PROJECT ALTERNATIVES

The alternatives typically included in CEQA documents for proposed South Coast AQMD rules, regulations, or plans are developed by breaking down the project into distinct components (e.g., emission limits, compliance dates, applicability, exemptions, pollutant control strategies, etc.) and varying the specifics of one or more of the components. Different compliance approaches that generally achieve the objectives of the project may also be considered as project alternatives. CEQA Guidelines Section 15126.6(b) states that the purpose of alternatives is to identify ways to mitigate or avoid significant effects that a project may have on the environment.

Alternatives to the proposed project were crafted by varying the emission reduction goals, the emission control technology, the implementation schedule, or the events (e.g., shutdowns, start-ups, malfunctions) allowed to demonstrate compliance. This proposed project was evaluated as control measure CMB-05 under the 2016 AQMP and was previously analyzed in the March 2017 Final Program EIR for the 2016 AQMP and the December 2015 Final PEA for NOx RECLAIM. The March 2017 Final Program EIR, which identified that only the components that pertain to the lowered BARCT NOx emission levels could entail physical modifications to the affected equipment, concluded that these physical modifications could create potential adverse significant impacts.

The December 2015 Final PEA for NOx RECLAIM conducted and presented an evaluation of the facilities that are now subject to PR 1109.1 and the actions required for their equipment to achieve BARCT levels for BARCT determined to apply to a market-based program. The BARCT determinations and the anticipated control technology installations have similarities in both the project previously evaluated in December 2015 Final PEA for NOx RECLAIM which focused on the NOx RTC shave and its effects and this proposed project. Some of the anticipated facility-specific projects that were evaluated previously evaluated in the December 2015 Final PEA for NOx RECLAIM have not yet been executed, but may potentially occur as well as overlap with implementation of PR 1109.1. However, because both of those previous CEQA evaluations were conducted on a programmatic level, the alternatives to this proposed project will be different and more reflective of the elements specified in PR 1109.1.

5.2 DESCRIPTION OF ALTERNATIVES TO THE PROPOSED PROJECT

Four alternatives to the proposed project are summarized in Table 5.4-1: Alternative A – No Project, Alternative B – More Stringent Proposed Project, Alternative C – Less Stringent Proposed Project, and Alternative D – Limited Start-up, Shutdown, Malfunction. The primary components of the proposed alternatives which have been modified are the source categories that may be affected, and the manner in which compliance with the proposed NOx BARCT emission limits in PR 1109.1 may be achieved. Unless otherwise specifically noted, all other components of the project alternatives are identical to the components of the proposed project.

The following subsections provide a brief description of the alternatives.

5.2.1 Alternative A – No Project

CEQA requires the specific alternative of "No Project" to be evaluated. A No Project Alternative consists of what would occur if the proposed project was not approved; in this case, not adopting the proposed project. Alternative A is the No Project approach such that petroleum refineries and facilities related to petroleum refineries would remain under the NOx RECLAIM program and not be subject to a command-and-control rule. The NOx RECLAIM program is based on a comprehensive set of rules, requirements, and procedures ensuring affected facilities operate under a mass emission cap with periodic reductions, or "shave," to demonstrate equipment operations are equivalent with BARCT. Meeting this shave can be done through installation and operation of control equipment, providing credits earned by other RECLAIM facilities through a trade, shutdown of equipment, etc. The proposed project is seeking to transition these facilities from the mass cap and trading credit approach to a command and control approach whereby each piece of equipment is accounted for under BARCT (e.g., NOx concentration limit).

However, facilities remaining subject to the RECLAIM program under Alternative A would still be subject to the 12 tons per day NOx RTC shave by the end of 2022 and the state law adopted pursuant to AB 617 which requires air districts "in nonattainment for one or more air pollutants to adopt an expedited schedule for the implementation of best available retrofit control technology, as specified." AB 617 applies to each industrial source that, as of January 1, 2017, was subject to a specified market-based compliance mechanism (e.g., CARB's AB 32 Cap-and-Trade program for GHGs) and gives highest priority to those permitted units that have not modified emissions-related permit conditions for the greatest period of time. Thus, facilities would still need to be evaluated under a BARCT analysis and, depending on the outcome of that analysis, would need to take action to comply. However, the BARCT analysis under Alternative A and the proposed project is expected to be the same with the same determinations and NOx emission limits. The major difference is that under the RECLAIM program, facilities could opt to use RECLAIM trading credits to meet allocation goals without having to make physical modifications such as installing air pollution control technology. Other elements in PR 1109.1 such as averaging times, exemptions, recordkeeping, reporting, and monitoring would also be different under the RECLAIM program. In addition, a directive in Action 5 of the Refinery priorities in the Wilmington, Carson, West Long Beach AB 617 CERP specifically contains a directive for South Coast AQMD to adopt PR 1109.1; thus, the No Project alternative would hinder the full implementation of this AB 617 communities' CERP, as well as implementation of control measure CMB-05 in the 2016 AQMP.

5.2.2 Alternative B – More Stringent Proposed Project

There are many elements in PR 1109.1 that could be adjusted to create a more stringent proposed project. To be more stringent would be to impose more requirements, lower standards to be achieved, or provide less flexibility or relief to those subject to the proposed rule. PR 1109.1 has been crafted to provide realistic parameters such as averaging times, exemptions, and implementation schedule. PR 1109.1 also contains requirements for some equipment categories, such as small heaters and boilers, that would not need to meet a lower NOx limit at this time due to the determination that it is either not cost effective under the BARCT analysis or the technology required to meet the lower limit is considered emerging. PR 1109.1, however, as outlined in Table 5.2-1, could require these equipment categories to meet the lower NOx limit sooner than the currently proposed. As proposed currently, small heaters with a heat input rating less than 40 MMBTU/hr would need to achieve the lower NOx limit at nine ppm via the application of emerging technology within 10 years after PR 1109.1 is adopted, and small boilers with a heat input rating of less than 40 MMBTU/hour must achieve five ppm NOx once the operator cumulatively replaces 50 percent or more of the burners starting from the date of rule adoption. Operators are required to maintain records of the burner replacements for these boilers and process heaters. Alternative B would propose applying earlier deadlines so that the small heaters would need to achieve nine ppm NOx within five years, and small boilers would need to achieve five ppm NOx within six months of having 25% or more of the burners replaced. The overall NOx emission reductions from Alternative B when compared to the proposed project will be the same except that these benefits will be achieved sooner under Alternative B. All other elements, limits, and deadlines would be the same under Alternative B as is in the proposed project.

Table 5.2-1
Overview of Alternative B (More Stringent) Accelerating Future Lower NOx Limit

Refinery Equipment Category	**No. of Units in Category**	**Future NOx Limit** (ppm)	**Alternative B Implementation Date**	**2017 NOx Emissions** (tpd)	**NOx Emission Reduction** (tpd)
Heaters < 40 MMBtu/hr	67	9	Within 5 years of rule adoption	0.50	0.36
Boilers < 40 MMBtu/hr	5	5	Within 6 months of 25% or more of burners cumulatively being replaced	0.01	0.01
Total (tpd)				0.51	0.37

5.2.3 Alternative C – Less Stringent Proposed Project

Contrasting Alternative B, there are a number of elements in PR 1109.1 that could be adjusted to create a less stringent proposed project. To be less stringent would be to impose less requirements, higher emission limits to be achieved, or provide more flexibility or relief to those subject to the proposed rule. As discussed under Alternative A, applicable facilities are still subject to a BARCT analysis as required by AB 617, and procedure to make BARCT determinations (i.e., identifying a cost effective technologically feasible NOx emissions limit) are unlikely to change under any alternative scenario. Under Alternative C, the implementation period could be extended to provide more time for each facility's individual projects to take place to achieve the proposed lower NOx limit. Under the proposed project, operators with six or more units complying with Table 1, Table 2, a B-Plan, or a B-CAP in PR 1109.1 have the option to either: a) submit permit applications by July 1, 2023 and achieve the NOx and CO emission limits in Table 1 of PR 1109.1 no later than 36 months after a Permit to Construct is issued, or b) submit an I-Plan to achieve NOx and CO limits under a two- or three-phase timeline. The development of the I-Plan options in Table 6 of PR 1109.1 is a culmination of input from the refineries regarding timeframes and percent reductions; under Alternative C, the time frames could be extended and percentage reduction targets could be reduced in each phase as presented in Table 5.2-2. For example, under Option 1, the proposed rule seeks 70 percent reduction in the first phase, however, Alternative C would require 35 percent reduction in the first phase. Both Alternative C and the proposed project would still require the combustion units to meet the proposed NOx emission limit. While the overall quantity of anticipated NOx emission reductions would not be expected to change under Alternative C when compared to the proposed project, more time would be provided for the NO emission reductions to occur, and thus incremental benefit to the environment, are achieved would be delayed.

Table 5.2-2
Alternative C (Less Stringent) Implementation Schedule

		Phase I	Phase II	Phase III
I-Plan Option 1	**Percent Reduction Targets**	**70 → 35**	**100 → 50**	**N/A → 100**
	Permit Application Submittal Date	July 1, 2023	January 1, 2027	N/A → January 1, 2031
I-Plan Option 2	**Percent Reduction Targets**	**60 → 30**	**80 → 60**	**100**
	Permit Application Submittal Date	July 1, 2023	January 1, 2025	January 1, 2028
I-Plan Option 3	**Percent Reduction Targets**	**50 → 25**	**100 → 50**	**N/A → 100**
	Permit Application Submittal Date	January 1, 2025	January 1, 2029	N/A → January 1, 2033
I-Plan Option 4	**Percent Reduction Targets**	**50-60 → 30**	**80 → 60**	**100**
	Permit Application Submittal Date	N/A (need to comply by July 1, 2024	January 1, 2025	January 1, 2028
I-Plan Option 5	**Percent Reduction Targets**	**50 → 25**	**70→ 50**	**100**
	Permit Application Submittal Date	July 1, 2022	July 1, 2024	January 1, 2028

5.2.4 Alternative D – Limited Start-up, Shutdown, Malfunction

The proposed project would allow emissions occurring during start-ups, shutdowns, and malfunctions (SSM), pursuant to the definitions in the PR 429.1, to not be considered when determining compliance with the NOx emission limits in PR 1109.1. With such low NOx emissions limits in PR 1109.1, any spike in the emissions data during SSM events will make it very challenging, and in some cases impossible, to counterbalance. Understandably, facilities will experience SSM events when the air pollution control equipment is not yet functioning at its most efficient performance as, for example, the catalyst bed has yet to reach a temperature to be most effective, or there is a malfunction whereby emissions experience a spike. The proposed project limits the duration of the SSM event as well as limits the severity (e.g., peak NOx concentration in terms of ppm) of the event. While difficult to predict when these SSM events could occur and how impactful they could be, examination of past patterns and researching the duration periods that have been previously required either in the permit conditions or consent decrees helped develop the SSM allowances for the proposed project. Alternative D would reduce the duration of these SSM allowances when compared to the proposed project as outlined in Table 5.2-3.

Table 5.2-3
SSM Allowances in Proposed Project and Alternative D

Unit	Proposed Project SSM Not to Exceed (hours)	Alternative D SSM Not to Exceed (hours)
Boilers and Process Heaters without NOx Post-Combustion Control Equipment, Gas Turbines, Flares, Vapor Incinerators without NOx Post-Combustion Control Equipment or Castable Refractory	2	2
Boilers and Process Heaters with NOx Post-Combustion Control Equipment, Steam Methane Reformer Heaters, Sulfuric Acid Furnaces	48	24
Steam Methane Reformer with Gas Turbine	60	30
FCCUs, Petroleum Coke Calciner, or SRU/TG Incinerators	120	60

5.3 ALTERNATIVES ANALYSIS

The same environmental topic areas evaluated for the proposed project are analyzed for each alternative. The following subsections re-summarize impacts and significance conclusions from the proposed project before discussing each alternative.

5.3.1 Air Quality and Greenhouse Gas Emissions

5.3.1.1 Proposed Project

Potential direct and indirect air quality and GHG emissions impacts from the proposed project are summarized in the following subsection. For the complete analysis, refer to Subchapter 4.2 - Air Quality and Greenhouse Gas Emissions.

The proposed project is expected to result in approximately seven to eight tpd of NOx emission reductions from the installation and operation of control technology in order to comply with the lower NOx limits of PR 1109.1. Compliance with the NOx limits in the proposed rule may overlap with projects currently taking place to comply with the 2015 NOx RECLAIM shave. This is due to 2017 emissions being used as baseline for the BARCT analysis, and those emissions could have since been reduced if a RECLAIM shave project has taken place since 2017. The 2015 NOx RECLAIM shave sets reduction targets from 2016 through 2022, and compliance in earlier years was anticipated to be satisfied by the surrendering of RTCs.

For this proposed project, South Coast AQMD staff conducted a BARCT analysis for all 16 affected facilities and their approximately 300 pieces of equipment which would be subject to PR 1109.1. It was concluded that operators have multiple options when modifying existing equipment by retrofitting with air pollution control technology. Control for the following equipment and source categories were analyzed: 1) boilers; 2) gas turbines; 3) ground level flares; 4) FCCUs; 5) petroleum coke calciners; 6) process heaters; 7) SRU/TGUs; 8) SMR heaters; 9) SMR heaters with gas turbine; 10) sulfuric acid furnaces; and 11) vapor incinerators. Table 5.3-1 summarizes the proposed NOx limits and potential NOx control technologies per equipment/source category as part of implementing the proposed project.

Table 5.3-1
Potential NOx Control Devices Per Sector and Equipment/Source Category

Equipment/Source Category	Proposed NOx Limit from BARCT Analysis	Potential NOx Control Devices
Boilers	40 ppm (<40 MMBTU/hr) 5 ppm (> 40 MMBTU/hr)	Replace burners with ULNBs; SCR; or Combination of the two
Gas Turbines	2 ppm (fueled with natural gas) 3ppm (fueled with refinery fuel gas)	SCR
Ground Level Flares	20 ppm	No additional control, but for units that exceed 20 hours per year, replacement with low-NOx flare
Fluid Catalytic Cracking Units (FCCUs)	2 ppm (over 365 days) 5 ppm (over 7 days)	SCR
Petroleum Coke Calciner	5 ppm (over 365 days) 10 ppm (over 7 days)	SCR; LoTOx™ with WGS; or UltraCat ™ with DGS
Process Heaters	40 ppm (<40 MMBTU/hr) 5 ppm (> 40 MMBTU/hr)	Replace burners with ULNBs; SCR; or Combination of the two
Sulfur Recovery Unit / Tail Gas Units (SRU/TGUs)	30 ppm	Replace burners with ULNBs (some currently achieve the limit)
Steam Methane Reformer Heaters (without/with gas turbine)	5 ppm	Replace burners with ULNBs; SCR; or Combination of the two
Sulfuric Acid Furnaces	30 ppm	Currently achieving the NOx emission limit
Vapor Incinerators	30 ppm	Replace burners with ULNBs

Construction activities associated with installing or modifying existing air pollution control equipment are expected to generate significant and unavoidable adverse air quality and GHG impacts. Operational activities associated with periodic truck trips, such as the delivery of supplies to support the operations of the various control technologies and the removal of waste from the control processes for disposal or recycling, are expected to generate less than significant air quality impacts.

5.3.1.2 Alternative A – No Project

Under Alternative A, the petroleum refineries and facilities related to petroleum refineries would remain under the NOx RECLAIM program and would not be subject to a command-and-control rule. Since the transition of RECLAIM facilities into a command-and-control approach was the directive under control measure CMB-05 in the 2016 AQMP, the No Project alternative would hinder the full implementation of the control measure, and would not achieve the anticipated emission reductions in a timely manner, or satisfy the objectives of the proposed project. In addition, the No Project Alternative would not remove the requirements for a BARCT evaluation for NOx emission sources as required by CMB-05 of the 2016 AQMP and AB 617, which is a state law. AB 617 requires facilities, such as those subject to PR 1109.1, to be analyzed under BARCT and to implement BARCT in an expeditious manner. Because the feasibility of air pollution control technology and the costs to install and operate NOx control equipment would not change between analysis under the proposed project versus outside of the proposed project pursuant to the BARCT requirements in CMB-05 and AB 617, the NOx emission limit determinations from the BARCT analysis are expected to be the same under Alternative A. The primary difference between Alternative A and the proposed project would be the implementation schedule and the means by which compliance under the existing RECLAIM program is conducted.

Under the No Project Alternative, refineries continue under RECLAIM. Under RECLAIM, facilities must hold RTCs that are equal to or greater than their actual emissions. Operators under RECLAIM have the option to install pollution controls, shutdown or reduce the activity of a unit, or to purchase RTCs. Throughout RECLAIM, petroleum refineries have made some reductions, but in general have purchased RTCs as their primary compliance approach. The 2015 amendments to RECLAIM reduced RTC holdings for the largest holders of RTCs which was designed to result in a 12 ton per day reduction in RTC allocations. Based on the analysis in the 2015 RECLAIM amendments, it was assumed that if the petroleum refineries implemented BARCT that the remaining NOx emissions in 2023 would be 2.76 tons per day. Since facilities in RECLAIM have the option to purchase RTCs, there is no assurance facilities will install pollution controls or will opt to purchase RTCs. Based on 2017 emissions data, petroleum refineries represented 12.3 tons per day. Since the 2015 amendments, the South Coast AQMD has only received nine permit applications for SCR projects, representing approximately 2 tons per day of NOx reductions. Based on the 2020 actual emissions from petroleum refineries, the remaining emissions would be about 10.3 tons per day, which is significantly higher than the 2.76 tons per day expected through implementation of the 2015 RECLAIM amendments. In addition, 2023 holdings for petroleum refineries is 7.4 tons per day which is another indication that refineries would likely continue to use RTCs in lieu of installing pollution controls if the No Project Alternative were implemented. Implementation of PR 1109.1 will ensure 7 to 8 tons per day of NOx reductions at petroleum refineries.

Relative to the 2017 emissions this would represent 2023 remaining emissions of 3.3 to 2.3 tons per day, which is substantially lower than 10.3 tons per day.

If facilities under Alternative A decide to comply via the installation and operation of NOx control technology in lieu of surrendering NOx RTCs, then similar to the Proposed Project, air quality and GHG would be adversely impacted during the construction phase and air quality adversely impacted during operational phases according to the number of equipment modifications, the impacts of which were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. However, if NOx RTCs are used for the majority of compliance, then overall construction and operational emissions impacts would be less than what was previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Nonetheless, construction activities associated with installing or modifying existing air pollution control equipment and operational activities associated with periodic truck trips are expected and have the potential to generate significant adverse air quality and GHG impacts.

Because the NOx significance thresholds for construction and operational emissions are nominally low: 100 pounds per day and 55 pounds per day, respectively, and there are about a hundred potential projects, Alternative A could result in significant adverse air quality impacts during construction even if some facilities use RTCs to comply, but these impacts would likely be less significant than the proposed project assuming less control equipment projects would occur under Alternative A. Similarly, since GHG impacts were determined to be significant for the proposed project, GHG impacts would likely be significant under Alternative A, although to a lesser extent than the proposed project.

5.3.1.3 Alternative B – More Stringent Proposed Project

PR 1109.1 already contains some very low NOx limits that may be a challenge to achieve. Thus, proposing more stringent limits that are unlikely to be achievable is unrealistic and potentially infeasible. Alternative B would have the same emission reductions as the proposed project (e.g., reduce total operational NOx emissions by approximately 7 to 8 tpd and regional annual PM2.5 concentration by ~~0.12~~ 0.11 µg/m3 without increasing CO emissions by 2034), but Alternative B would achieve 0.37 ton per day (or 740 pounds per day from boilers and heaters < 40 MMBTU/hr years earlier than the proposed project by requiring 72 units to reduce their NOx emission concentrations sooner than what would otherwise occur under the proposed project timeline. This could also lead to an increase in construction emission impacts if more projects are being implemented on a given day. Ultimately, however, the proposed project will achieve the same quantity of NOx emission reductions once controls are installed and operating. Regardless of the implementation timeline, these estimated NOx emission reductions can only be achieved if facilities replace existing burners with ULNBs or install new air pollution control equipment. The BARCT determination is not expected to be different from the proposed project so all other equipment categories, NOx limits, and actions to be taken to achieve those limits are expected to be the same under Alternative B as they are for the proposed project.

Construction activities associated with installing or modifying existing air pollution control equipment and operational activities associated with periodic truck trips are expected and have the potential to generate significant adverse air quality impacts. Since the air quality impacts during construction were determined to be significant for the proposed project, the air quality impacts during construction would be significant under Alternative B. Similarly, since the GHG impacts were determined to be significant for the proposed project, the GHG impacts would be significant under Alternative B. Similar to the proposed project, the operational air quality impacts would not be significant as air quality will benefit from emission reductions.

5.3.1.4 Alternative C – Less Stringent Proposed Project

Contrasting Alternative B, there are a number of elements in PR 1109.1 that could be adjusted to create a less stringent proposed project; however, doing so would forego the potential to achieve NOx emission reductions to the fullest extent, as well as undermine the objectives of the proposed project. The BARCT analysis to determine the NOx emission concentration limit for each equipment and source category at the affected facilities is expected to be the same for the proposed project and Alternative C. An alternative that provides less stringent concentration limits could be subject to legal challenge. Thus, the most defensible way to provide a less stringent alternative is to ease the implementation schedule as presented in Table 5.2-2. Alternative C would have the same emission reductions as the proposed project (e.g., reduce total operational NOx emissions by approximately 7 to 8 tpd and regional annual PM2.5 concentration by ~~0.12~~ 0.11 µg/m3 without increasing CO emissions by 2034), but the timing for achieving the corresponding NOx emission reductions could be lengthened if facility operators elect to implement the alternative I-Plan option, which will have fewer incremental NOx emission reductions occur early in Phases I and II, but with 100% of the NOx emission reductions being achieved by Phase III. Thus, by extending the timing to submit permit applications and the corresponding implementation deadlines under Alternative C, there would be a delay in the overall and incremental NOx emission reductions when compared to the proposed project. In turn, the delay could potentially lessen the intensity of the significant adverse air quality impacts during overlapping construction and operation activities on peak day when compared to the proposed project. Since the GHG impacts have a cumulative effect over the long-term, the GHG impacts under Alternative C would be expected to stay about the same as the proposed project.

Construction activities associated with installing or modifying existing air pollution control equipment and operational activities associated with periodic truck trips are expected and have the potential to generate significant adverse air quality impacts. Since the air quality impacts during construction were determined to be significant for the proposed project, the air quality impacts during construction would be significant under Alternative C. Similarly, since the GHG impacts were determined to be significant for the proposed project, the GHG impacts would be significant under Alternative C.

5.3.1.5 Alternative D – Limited Start-Up, Shutdown, Malfunction

Alternative D would have the same emission reductions as the proposed project (e.g., reduce total operational NOx emissions by approximately 7 to 8 tpd and regional annual PM2.5 concentration by ~~0.12~~ 0.11 µg/m3 without increasing CO emissions by 2034), but with limited NOx emissions occurring during intermittent SSM events when compared to the proposed project. SSM events for equipment are expected at every facility but, it is challenging and speculative to predict when and how long any SSM event could occur. While PR 429.1 would allow NOx emissions occurring when air pollution control equipment is intermittently offline during SSM events, pursuant to the definitions in the PR 429.1, to not be considered when determining compliance with the NOx emission limits, PR 429.1 also prescribes a duration limit for those SSM events. By further reducing the time allowed for an SSM event to occur, Alternative D would require more NOx emissions to be included in the compliance determination when compared to the proposed project. Thus, facilities would need to be more diligent in following their SSM procedures to ensure quick turnarounds to reduce the chances for spikes in emissions during SSM events. More attention to maintenance and upkeep of equipment would be needed to reduce the number of malfunctions contributing to air pollution control equipment being offline. If additional measures are not taken to reduce the duration or severity of peak NOx emissions during an SSM event under Alternative D, the quantity of emissions occurring during a temporary spike outside of the allowed duration window would need to be accounted for in the emissions total used to demonstrate compliance with the NOx limits in PR 1109.1. In theory, if SSM emissions are incorporated into the lifetime total emissions for a piece of equipment, Alternative D will reduce the overall operational process emissions from facilities.

Construction activities associated with installing or modifying existing air pollution control equipment and operational activities associated with periodic truck trips are expected to be similar to those under the proposed project and have the potential to generate significant adverse air quality impacts. Since the air quality impacts during construction were determined to be significant for the proposed project, the air quality impacts during construction would be significant under Alternative D. Similarly, since the GHG impacts were determined to be significant for the proposed project, the GHG impacts would be significant under Alternative D. In addition, by further limiting the duration of SSM events, Alternative D could result in more effective management of SSM events which may provide a slight benefit to the overall operational process NOx emissions since less NOx emissions generated during SSM events would be allowed.

5.3.2 Hazards and Hazardous Materials

5.3.2.1 Proposed Project

Potential hazards and hazardous materials impacts from the proposed project are summarized in the following subsection. For the complete analysis, refer to Subchapter 4.3 - Hazards and Hazardous Materials.

NOx is reduced by the installation of new control or modification of existing equipment. Because some types of air pollution control equipment rely on chemicals such as ammonia and catalysts (e.g., SCRs and UltraCat^{TM} with DGS), implementing the proposed project will increase the use, storage and transport of hazards and hazardous materials during operational-related activities. The analysis of hazards and hazardous materials impacts due to implementing the proposed project focuses on: 1) the anticipated increase of hazardous substances used to operate the new or modified NOx controls; and 2) the potential increased capture of hazardous substances as part of the overall NOx reduction effort. The analysis of the proposed project in this SEA concluded that significant adverse impacts due to the routine transport, use, and storage of ammonia and some facilities' proximity to schools would be expected but that the spent catalysts would not generate any hazardous substances. Because the alternatives do not have varying locations for potential new installation and retrofit projects, this discussion focuses on the hazards and hazardous materials impacts from the routine transport, use, and storage of ammonia.

5.3.2.2 Alternative A – No Project

Under Alternative A, the petroleum refineries and facilities related to petroleum refineries would remain under the NOx RECLAIM program and would not be subject to a command-and-control rule. In addition, the No Project Alternative would not remove the requirements of state law, AB617, which requires facilities, such as those subject to PR 1109.1, to be analyzed under BARCT and to implement BARCT in an expeditious manner. Because the feasibility of air pollution control technology and the costs to install and operate NOx control equipment would not change between analysis under the proposed project versus outside of the proposed project but under AB617, the NOx emission limit determinations from the BARCT analysis would be expected to be the same. The primary difference between Alternative A and the proposed project would be the implementation schedule and the means by which compliance under the existing RECLAIM program is conducted. Under RECLAIM, facilities are allowed to demonstrate compliance with the BARCT determinations by providing RTCs in addition to installing and operating NOx control equipment. While the exact number is speculative, based on historical records of NOx RECLAIM practice, most facilities would proceed providing RTCs. The use of NOx RTCs does not mean that NOx emission reductions on a regional basis are not achieved.

If facilities under Alternative A decide to comply via the installation and operation of NOx control technology in lieu of surrendering NOx RTCs, then similar to the Proposed Project, the use, storage, and transport of hazards and hazardous materials, such as ammonia needed for operating SCRs and UltraCat^{TM} with DGS, would be adversely impacted during operation according to the number of equipment modifications, the impacts of which were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. However, if RTCs are used for the majority of compliance efforts, then overall hazards and hazardous materials impacts associated with the transportation, storage, and use of ammonia would be less than what was previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Nonetheless, hazards and hazardous materials impacts associated with the transportation, storage, and use of ammonia are expected to have the potential to generate significant adverse hazards and hazardous materials impacts.

While Alternative A would not likely result in the same number of individual facility projects as the proposed project, due to the large number of potential projects that may involve the use of ammonia, Alternative A is also concluded to have the potential to generate significant hazards and hazardous materials impacts associated with the transportation, storage, and use of ammonia.

5.3.2.3 Alternative B – More Stringent Proposed Project

Alternative B would propose applying earlier deadlines so that the small heaters would need to achieve nine ppm NOx within five years, and small boilers would need to achieve five ppm NOx within six months of having 25% or more of the burners replaced. The overall NOx emission reductions from Alternative B when compared to the proposed project will be the same except that these benefits will be achieved sooner under Alternative B. All other elements, limits, and deadlines would be the same under Alternative B as is in the proposed project

Adjusting the deadlines for small heaters and boilers to achieve the NOx limits prescribed in PR 1109.1, facilities would be expected to install and operate the NOx control equipment more quickly under a more compressed timeline. The overall NOx emission reductions from Alternative B when compared to the proposed project will be the same except that these benefits will be achieved sooner under Alternative B. Regardless of the implementation timeline, the estimated NOx emission reductions under both the proposed project and Alternative C can only be achieved if facilities replace existing burners with ULNBs and install new air pollution control equipment. Thus, the types of NOx control technologies under Alternative B would be the same as the proposed project as summarized in Table 5.3-1.

Relative to the topic of hazards and hazardous materials, both the proposed project and Alternative B anticipate the same type and quantity of NOx control technologies will be employed, such as SCRs and UltraCat^{TM} with DGS, which require ammonia, a hazardous material, for their operation. The analysis of hazards and hazardous materials impacts for the proposed project concluded significant adverse hazards and hazardous materials impacts related to the transportation, storage, and use of ammonia, which may be used to operate the aforementioned NOx control equipment, and this same conclusion would apply to Alternative B.

5.3.2.4 Alternative C – Less Stringent Proposed Project

By easing the implementation schedule under Alternative C to allow more time to achieve the same NOx limits and reduce the same quantity of NOx emissions as the proposed project, the

NOx control equipment would be installed at a slower pace under Alternative C. Also, the overall NOx emission reductions from Alternative C when compared to the proposed project will be the same except that these benefits will be achieved later under Alternative C. Regardless of the implementation timeline, the estimated NOx emission reductions under both the proposed project and Alternative C can only be achieved if facilities replace existing burners with ULNBs and install new air pollution control equipment.

Thus, the types of control technologies under Alternative C would be the same as the proposed project as summarized in Table 5.3-1.

Relative to the topic of hazards and hazardous materials, both the proposed project and Alternative C anticipate the same type and quantity of NOx control technologies will be employed, such as SCRs and UltraCat™ with DGS, which require ammonia, a hazardous material, for their operation. The analysis of hazards and hazardous materials impacts for the proposed project concluded significant adverse hazards and hazardous materials impacts related to the transportation, storage, and use of ammonia, which may be used to operate the aforementioned NOx control equipment, and this same conclusion would apply to Alternative C.

5.3.2.5 Alternative D – Limited Start-Up, Shutdown, Malfunction

Under Alternative D, the implementation time, BARCT determination, NOx limits, control technologies to achieve the NOx limits in PR 1109.1, as well as the number of projects requiring the installation and operation of air pollution control technology as summarized in Table 5.3-1 would be the same as the proposed project. Relative to the topic of hazards and hazardous materials, both the proposed project and Alternative D anticipate the same type and quantity of NOx control technologies will be employed, such as SCRs and UltraCat™ with DGS, which require ammonia, a hazardous material, for their operation. By further reducing the time allowed for an SSM event to occur, Alternative D would have more NOx emissions that would need to be included in the compliance determination when compared to the proposed project but this will not change the amount of ammonia projected to be needed to operate SCRs and UltraCat™ with DGS when they are online, provided these types of air pollution control technologies are installed. However, during SSM events occurring either under the proposed project or Alternative D, ammonia will not be utilized when the SCRs and UltraCat™ with DGS are offline. Once the SCRs and UltraCat™ with DGS return to service, the use of ammonia will also resume. Since the duration of allowed SSM events will be shorter under Alternative D when compared to the proposed project, once the SCRs and UltraCat™ with DGS return to service, which will be sooner for Alternative D, the resumed use of ammonia will also occur sooner. For this reason, Alternative D may utilize slightly more ammonia than the proposed project when SCRs and UltraCat™ with DGS resume operation after an SSM event.

The analysis of hazards and hazardous materials impacts for the proposed project concluded significant adverse hazards and hazardous materials impacts related to the transportation, storage, and use of ammonia, which may be used to operate the aforementioned NOx control equipment, and this same conclusion would apply to Alternative D.

5.3.3 Hydrology

5.3.3.1 Proposed Project

Potential hydrology impacts from the proposed project are summarized in the following subsection. For the complete analysis, refer to Subchapter 4.4 - Hydrology.

This SEA tiers off two previous programmatic CEQA documents: the December 2015 Final PEA for NOx RECLAIM and the March 2017 Final Program EIR for the 2016 AQMP. This SEA is a subsequent document to the December 2015 Final PEA for NOx RECLAIM. Because this is a subsequent document, the baseline is the project analyzed in the December 2015 Final PEA for NOx RECLAIM.

The December 2015 Final PEA for NOx RECLAIM specifically evaluated hydrology impacts during construction activities associated with installing the various control equipment when soil disturbance is involved, and during operation from new or modified add-on air pollution control equipment that use water for their operation, e.g., scrubbers such as LoTOx^{TM} with WGS. The December 2015 Final PEA for NOx RECLAIM also analyzed water use associated with hydrotesting the ammonia storage tanks.

The hydrology (water demand) analysis in this SEA identifies the net effect of implementing the proposed project in comparison to the project that was previously analyzed in the December 2015 Final PEA for NOx RECLAIM which involves: 1) the installation up to 74 additional new SCRs and associated ammonia storage tanks; 2) upgrading an additional 16 existing SCRs; and 3) replacing 76 existing burners with ULNBs. Installation of technologies such as LoTOx^{TM} with and without WGSs and UltraCat^{TM} with DGS that were previously analyzed in the December 2015 Final PEA for NOx RECLAIM will also be expected to occur under the proposed project.

The proposed project applies to 16 facilities and nine of these facilities were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Even though more facilities and more combustion equipment categories will be affected by the proposed project, the key differences between the analyses in these two previous CEQA documents and this SEA for the proposed project are that this SEA updates the previous CEQA analysis relative to hydrology impacts to: 1) adjust the amount of water that will be needed for dust mitigation during construction when soil disturbance is involved to account for the installation of additional new SCRs and associated ammonia storage tanks; and 2) adjust the quantity of water needed to conduct hydrotesting of the new ammonia storage tanks after they are installed.

However, since SCR technology and UltraCat^{TM} with DGS do not utilize water for its operation, no increases in operational water are anticipated.

Also, while the proposed project may involve the installation of LoTOx^{TM} with WGSs, which utilize water for their operation, these air pollution control devices and the associated water use were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Moreover, the proposed project neither contains any changes to the type of combustion equipment that would utilize LoTOx^{TM} with WGSs nor requires any updates to the amount of water use that will be needed for their operation. Thus, an updated hydrology analysis of scrubber-related impacts was not included in this SEA.

Finally, while the potential for replacing existing burners with ULNBs in some combustion equipment and the associated environmental impacts were not previously analyzed in the December 2015 Final PEA for NOx RECLAIM, no new hydrology analysis of ULNB-related impacts was conducted for construction or operation because: 1) the installation of ULNBs do not involve construction activities that would disturb soil and cause fugitive dust; and 2) ULNBs do not require any water for their operation.

Thus, the hydrology analysis in this SEA focuses on the changes in water use for fugitive dust control during construction of the additional new SCRs and associated ammonia storage tanks, and for hydrotesting of ammonia storage tanks after they are installed as part of implementing the proposed project when compared to the previous hydrology impact analysis in the December 2015 Final PEA for NOx RECLAIM.

For water needed for fugitive dust control purposes during construction, the hydrology analysis in this SEA concluded less than significant adverse hydrology impacts and the hydrology analysis in the December 2015 Final PEA for NOx RECLAIM reached the same conclusion. When considered together, the total amount of water that may be needed for fugitive dust control purposes during construction was also concluded to have less than significant adverse water demand impacts. Further, it is not expected that hydrotesting and construction impacts would overlap since the hydrotesting occurs once the equipment is installed and construction is complete.

For water needed to conduct hydrotesting of the new ammonia storage tanks post-construction, the analysis in this SEA concluded less than significant hydrology impacts since the significance thresholds for potable water and total water would not be exceeded. However, the hydrology analysis in the December 2015 Final PEA for NOx RECLAIM concluded potentially significant adverse hydrology impacts from hydrotesting ammonia storage tanks because the significance threshold for potable water would be exceeded. Thus, when considered together, the total amount of potable water that may be needed to conduct hydrotesting was concluded to have significant adverse hydrology impacts due to the potential demand for potable water.

For operational water, the proposed project evaluated in this SEA would not contribute any new operational water demand impacts. However, the hydrology analysis in the December 2015 Final PEA for NOx RECLAIM concluded potentially significant adverse hydrology impacts during operation, primarily for use in the LoTOx™ with WGSs, because the significance threshold for potable water would be exceeded. Thus, when considered together, the total amount of potable water that may be needed during operation for the proposed project, was concluded to have significant adverse hydrology impacts due to the potential demand for potable water.

5.3.3.2 Alternative A – No Project

Under Alternative A, the petroleum refineries and facilities related to petroleum refineries would remain under the NOx RECLAIM program and would not be subject to a command-and-control rule. In addition, the No Project Alternative would not remove the requirements of state law, AB617, which requires facilities, such as those subject to PR 1109.1, to be analyzed under BARCT and to implement BARCT in an expeditious manner. Because the feasibility of air pollution control technology and the costs to install and operate NOx control equipment would not change between the analysis under the proposed project versus outside of the proposed project but under AB617, the NOx emission limit determinations from the BARCT analysis would be expected to be the same. The primary difference between Alternative A and the proposed project would be the implementation schedule and the means by which compliance under the existing RECLAIM program is conducted. Under RECLAIM, facilities are allowed to demonstrate compliance with the BARCT determinations by providing RTCs in addition to installing and operating NOx control equipment. While the exact number is speculative, based on historical records of NOx RECLAIM practice, most facilities would proceed by providing RTCs.

If facilities under Alternative A decide to comply via the installation and operation of NOx control technology in lieu of surrendering NOx RTCs, then similar to the Proposed Project, adverse impacts to hydrology would be expected to occur during the construction and operational phases according to the number of equipment modifications, the impacts of which were previously analyzed in the December 2015 Final PEA for NOx RECLAIM. However, if NOx RTCs are used for the majority of compliance, then overall construction and operational hydrology impacts would be less than what was previously analyzed in the December 2015 Final PEA for NOx RECLAIM. Nonetheless, construction activities associated with installing or modifying existing air pollution control equipment as well as operating the air pollution control equipment are expected to require water and create hydrology impacts.

Because the significance thresholds for hydrology vary substantially for potable water when compared to total water, 262,820 gallons per day and five million gallons per day, respectively, and there are approximately one hundred potential projects that could occur under Alternative A similar to the proposed project, Alternative A could result in significant adverse hydrology impacts during hydrotesting as well as during operation of air pollution control equipment that utilizes water (e.g., LoTOx^{TM} with WGSs).

Therefore, as with the proposed project, Alternative A will be expected to have: 1) less than significant adverse hydrology impacts due to water needed for fugitive dust control purposes during construction; 2) potentially significant adverse hydrology impacts due to water needed to conduct hydrotesting; and 3) potentially significant adverse hydrology impacts due to water needed to operate air pollution control equipment that utilize water, primarily LoTOx^{TM} with WGSs.

5.3.3.3 Alternative B – More Stringent Proposed Project

Under Alternative B, the same facility-specific projects as would be implemented under the proposed project would be expected to occur, but within a shorter timeline that what would otherwise occur under the proposed project. As such, Alternative B would be expected to have the same construction activities requiring the same amount of water for fugitive dust suppression purposes during construction, the same amount of water needed to conduct hydrotesting, and the same amount of water for operating air pollution control equipment that need water to function (e.g., LoTOx™ with WGSs) as would be needed under the proposed project. It is not expected that hydrotesting and dust suppression would overlap since the hydrotesting occurs once the equipment is installed and construction is complete.

Therefore, as with the proposed project, Alternative B will be expected to have: 1) less than significant adverse hydrology impacts due to water needed for fugitive dust control purposes during construction; 2) potentially significant adverse hydrology impacts due to water needed to conduct hydrotesting; and 3) potentially significant adverse hydrology impacts due to water needed to operate air pollution control equipment that utilize water, primarily LoTOx™ with WGSs.

5.3.3.4 Alternative C – Less Stringent Proposed Project

Under Alternative C, the same facility-specific projects as would be implemented under the proposed project would be expected, but over a longer period of time than what would otherwise occur under the proposed project. As such, potentially fewer of the facility-specific projects have the potential to overlap construction activities on a peak day. While Alternative C would be expected to have the same construction activities as the proposed project, either the same or less amount of water for fugitive dust suppression purposes and hydrotesting may be needed under Alternative C, when compared to the proposed project. During operation of air pollution control equipment that need water to function (e.g., LoTOx™ with WGSs) the same amount of water would be needed under Alternative C, when compared to the proposed project. Since information about how many fewer facility-specific projects may overlap on peak day is unknown at this time, the conclusions for hydrology impacts for the proposed project will also apply to Alternative C.

Therefore, as with the proposed project, Alternative C will be expected to have: 1) less than significant adverse hydrology impacts due to water needed for fugitive dust control purposes during construction; 2) potentially significant adverse hydrology impacts due to water needed to conduct hydrotesting; and 3) potentially significant adverse hydrology impacts due to water needed to operate air pollution control equipment that utilize water, primarily LoTOx™ with WGSs.

5.3.3.5 Alternative D – Limited Start-Up, Shutdown, Malfunction

Under Alternative D, the same facility-specific projects as would be implemented under the proposed project would be expected to occur. As such, Alternative D would be expected to have the same construction activities requiring the same amount of water for fugitive dust suppression purposes, the same amount of water needed to conduct hydrotesting, and the same amount of water for operating air pollution control equipment that need water to function (e.g., LoTOx™ with WGSs) as would be needed for the proposed project.

Therefore, as with the proposed project, Alternative D will be expected to have: 1) less than significant adverse hydrology impacts due to water needed for fugitive dust control purposes during construction; 2) potentially significant adverse hydrology impacts due to water needed to conduct hydrotesting; and 3) potentially significant adverse hydrology impacts due to water needed to operate air pollution control equipment that utilize water, primarily LoTOx™ with WGSs.

5.4 COMPARISON OF ALTERNATIVES TO THE PROPOSED PROJECT

Pursuant to CEQA Guidelines Section 15126.6(d), a CEQA document "shall include sufficient information about each alternative to allow meaningful evaluation, analysis, and comparison with the proposed project." A matrix displaying the major characteristics and significant environmental effects of each alternative may be used to summarize the comparison. If an alternative would cause one or more significant effects in addition to those that would be caused by the project as proposed, the significant effects of the alternative shall be discussed, but in less detail than the significant effects of the project as proposed." Accordingly, Table 5.4-1 provides a matrix displaying the major differences in characteristics between the proposed project and each alternative, and Table 5.4-2 compares the environmental impacts between the proposed project and each alternative.

Table 5.4-1
Summary of Proposed Project and Alternatives

Rule Elements	Proposed Project	Alternative A: No Project	Alternative B: More Stringent Proposed Project	Alternative C: Less Stringent Proposed Project	Alternative D: Limited Start-Up, Shutdown, Malfunction
BARCT NOx Limits	*Boilers:* 40 ppm (<40 MMBTU/hr)[a], 5 ppm (>40 MMBTU/hr) *Gas Turbines:* 2 ppm (natural gas), 3ppm (refinery fuel gas) *Ground Level Flares:* 20 ppm *FCCUs:* 2 ppm (over 365 days), 5 ppm (over 7 days) *Petroleum Coke Calciner:* 5 ppm (over 365 days) 10 ppm (over 7 days) *Process Heaters:* 40 ppm (<40 MMBTU/hr)[b], 5 ppm (> 40 MMBTU/hr) *SRU/TGUs:* 30 ppm *SMR Heaters:* 5 ppm *Sulfuric Acid Furnaces:* 30 ppm *Vapor Incinerators:* 30 ppm	The facilities would still be subject to AB617 which requires BARCT analysis and implementation of BARCT as soon as possible; thus, the limits would be the same as under the proposed project. However, instead of the command-and-control approach under the PR 1109.1 implementation schedule, the facilities would demonstrate compliance under the existing RECLAIM program which allows for RTCs, and according to the analysis conducted in the December 2015 Final PEA for NOx RECLAIM.	Same as Proposed Project	Same as Proposed Project	Same as Proposed Project
Potential NOx Emission Reductions	Approximately 7 to 8 tpd	2 tpd[c]	Same as Proposed Project	Same as Proposed Project	Same as Proposed Project
Heaters (< 40 MMBTU/hr) at 9 ppm NOx[b]	Compliance within 10 years from rule adoption	Indefinite. Timeline for demonstration of BARCT would occur according to the existing NOx RECLAIM program.	Compliance within 5 years from rule adoption	Same as Proposed Project	Same as Proposed Project
Boilers (<40 MMBTU/hr) at 5 ppm NOx[c]	Compliance within 6 months for 50% or more of burners cumulatively being replaced	Indefinite. Timeline for demonstration of BARCT would occur according to the existing NOx RECLAIM program.	Compliance within 6 months for 25% or more of burners cumulatively being replaced	Same as Proposed Project	Same as Proposed Project

Table 5.4-1 (concluded)
Summary of Proposed Project and Alternatives

Rule Elements	Proposed Project	Alternative A: No Project	Alternative B: More Stringent Proposed Project	Alternative C: Less Stringent Proposed Project	Alternative D: Limited Start-Up, Shutdown, Malfunction
I-Plan	Option 1: 70% at Phase I, 100% at Phase II Option 2: 60% at Phase I, 80% at Phase II, 100% at Phase III Option 3: 50% at Phase I, 100% at Phase II Option 4: 50-60% at Phase I, 80% at Phase II 100% at Phase III Option 5: 50% at Phase I, 70% at Phase II 100% at Phase III	Indefinite. Timeline for demonstration of BARCT would occur according to the existing NOx RECLAIM program.	Same as Proposed Project	Option 1: 35% at Phase I, 50% at Phase II, 100% at Phase III Option 2: 30% at Phase I, 60% at Phase II, 100% at Phase III Option 3: 25% at Phase I, 50% at Phase II, 100% at Phase III Option 4: 30% at Phase I, 60% at Phase II 100% at Phase III Option 5: 25% at Phase I, 50% at Phase II 100% at Phase III	Same as Proposed Project
Start-Up, Shutdown and Malfunction Allowance	*Gas Turbines:* 2 hours *Boilers, Process Heaters, & SMR Heaters:* 48 hours *SMR with Gas Turbine:* 60 hours *FCCUs, Petroleum Coke Calciner, and SRU/TG Incinerators:* 120 hours	No allowances would be necessary because demonstration of BARCT would occur according to the existing NOx RECLAIM program.	Same as Proposed Project	Same as Proposed Project	*Gas Turbines:* 2 hours *Boilers, Process Heaters, & SMR Heaters:* 24 hours *SMR with Gas Turbine:* 30 hours *FCCUs, Petroleum Coke Calciner, and SRU/TG Incinerators:* 60 hours

a Boilers (<40 MMBTU/hr) are currently subject to a 40ppm NOx limit, but will be subject to a 5ppm NOx limit within 6 months of 50% of more of the burners cumulatively being replaced.
b Heaters (<40 MMBTU/hr) are currently subject to a 40ppm NOx limit, but will be subject to a 9ppm NOx limit within 10 years of rule adoption.
c Actual emission reductions under this alternative appear to be substantially less than the amount predicted in the 2015 RECLAIM amendment. See discussion in section 5.3.1.2 Alternative A – No Project.

Table 5.4-2
Comparison of Adverse Environmental Impacts of the Proposed Project and Alternatives

Environmental Topic Area	Proposed Project	Alternative A: No Project	Alternative B: More Stringent Proposed Project	Alternative C: Less Stringent Proposed Project	Alternative D: Limited Start-Up, Shutdown, Malfunction
Air Quality & GHGs	• Reduces total operational NOx emissions by approximately 7 to 8 tpd and annual PM2.5 concentration by ~~0.12~~ 0.11 µg/m3 without increasing CO emissions via air pollution control equipment at full implementation by 2034 • With mitigation, significant unavoidable increase in peak daily emissions for construction: VOC: ~~178~~ 155 lbs/day NOx: ~~873~~ 1,062 lbs/day CO: ~~4,941~~ 4,306 lbs/day SOx: ~~9~~ 8 lbs/day PM10: ~~128~~ 183 lbs/day PM2.5: ~~52~~ 60 lbs/day • Without mitigation, less-than-significant increase in peak daily emissions for operation: VOC: < 1 lb/day NOx: -13,980 lbs/day CO: 2 lbs/day SOx: < 1 lb/day PM10: < 1 lb/day PM2.5: < 1 lb/day • Without mitigation, less-than-significant increase in annual GHGs of ~~2,051~~ 2,029 MT/yr • Restricting the duration of SSM events will limit an unquantifiable amount of intermittent emissions of NOx that will occur when air pollution control equipment is offline • Sources of health risk are diesel particulate matter from construction and ammonia usage from operation. Health risk from short term construction (maximum 3 years) cannot be reliably quantified because cancer risk is calculated with 25, 30, or 70 year exposure rates. Operational use of ammonia will result in acute and chronic hazard indexes less than the threshold of 1.0. • Ammonia is limited to 5 ppm	• Reduced NOx allocations by 12 tpd NOx fulfilled primarily by surrender of RTCs, with full implementation by December 31, 2022 • In lieu of surrendering RTCs, NOx reduction projects could be conducted according to the December 2015 Final PEA for NOx RECLAIM. Peak day construction emissions, peak day operational emissions, and total GHGs would be the same as previously analyzed in the December 2015 Final PEA for NOx RECLAIM and the • Implementation of CMB-05 per the 2016 AQMP as analyzed in the March 2017 Final Program EIR for 2016 AQMP will continue to be required in accordance with BARCT • BARCT per AB 617 will continue to be required.	• Reduces total operational NOx emissions by approximately 7 to 8 tpd and annual PM2.5 concentration by ~~0.12~~ 0.11 µg/m3 without increasing CO emissions via air pollution control equipment at full implementation by 2034, but with 0.37 tpd of NOx emission reductions from boilers and heaters < 40 MMBTU/hr achieved sooner than proposed project. • Peak day construction emissions, peak day operational emissions, and total GHGs are expected to be the same as the proposed project.	• Reduces total operational NOx emissions by approximately 7 to 8 tpd and annual PM2.5 concentration by ~~0.12~~ 0.11 µg/m3 without increasing CO emissions via air pollution control equipment at full implementation by 2034, but with fewer incremental NOx emission reductions occurring early in Phases I and II for each I-Plan option, but with 100% of the NOx emission reductions being achieved by Phase III. • Peak day construction emissions, peak day operational emissions, and total GHGs are expected to be the same as the proposed project.	• Reduces total operational NOx emissions by approximately 7 to 8 tpd and annual PM2.5 concentration by ~~0.12~~ 0.11 µg/m3 without increasing CO emissions via air pollution control equipment at full implementation by 2034 • Peak day construction emissions, peak day operational emissions, and total GHGs are expected to be the same as the proposed project. • Reducing the time allowed for SSM events by 50% for the same equipment categories as the proposed project, except for gas turbines, will further limit an unquantifiable amount of NOx emissions by 50% when air pollution control equipment is offline.

Table 5.4-2 (continued)
Comparison of Adverse Environmental Impacts of the Proposed Project and Alternatives

Environmental Topic Area	Proposed Project	Alternative A: No Project	Alternative B: More Stringent Proposed Project	Alternative C: Less Stringent Proposed Project	Alternative D: Limited Start-Up, Shutdown, Malfunction
Air Quality & GHG Impacts Significant?	• **Significant and unavoidable air quality impacts from construction** for VOC, NOx, and CO for PR 1109.1. The December 2015 Final PEA for NOx RECLAIM also concluded significant and unavoidable air quality construction impacts, and the proposed project increases the severity of the previous analysis. • **Less than significant air quality impacts from operation** for PR 1109.1. The project also achieves a net NOx emission reduction by approximately 7 to 8 tpd. The December 2015 Final PEA for NOx RECLAIM also concluded less than significant air quality operation impacts, and the proposed project increases the severity of the previous analysis while not changing the significance conclusion. • While calculations show less than significant GHG emissions for PR 1109.1, the December 2015 Final PEA for NOx RECLAIM concluded significant unavoidable GHG impacts; therefore **significant and unavoidable GHG impacts** are expected with this proposed project. • **Less than significant health risk impact** for PR 1109.1. The December 2015 Final PEA for NOx RECLAIM also concluded less than significant health risk impact. • **Less than significant odor nuisance impact** for PR 1109.1. The December 2015 Final PEA for NOx RECLAIM also concluded less than significant odor nuisance impact.	• The December 2015 Final PEA for NOx RECLAIM concluded significant and unavoidable construction impacts for air quality, less than significant operational impacts, and significant unavoidable impacts for GHGs.	• The overall conclusions for construction and operation impacts are the same as the proposed project even though the portion of NOx emission reductions from boilers and heaters < 40 MMBTU/hr will be achieved sooner than proposed project.	• The overall conclusions for construction and operation impacts are the same as the proposed project, even with fewer incremental NOx emission reductions occurring early in Phases I and II for each I-Plan option, but with 100% of the NOx emission reductions being achieved by Phase III.	• The overall conclusions for construction and operation impacts are the same as the proposed project even though intermittent emissions of NOx occurring during SSM events are expected to be less than the proposed project

Table 5.4-2 (continued)
Comparison of Adverse Environmental Impacts of the Proposed Project and Alternatives

Environmental Topic Area	Proposed Project	Alternative A: No Project	Alternative B: More Stringent Proposed Project	Alternative C: Less Stringent Proposed Project	Alternative D: Limited Start-Up, Shutdown, Malfunction
Hazards & Hazardous Materials	• Increased use of approximately ~~4~~ 5 tons/day of NH3 used during operation.	• NOx reduction projects would be conducted according to the December 2015 Final PEA for NOx RECLAIM. Ammonia usage would be the same as previously analyzed in the December 2015 Final PEA for NOx RECLAIM.	• Same as proposed project	• Same as proposed project	• Same as proposed project
Hazards & Hazardous Materials Impacts Significant?	• **Significant** impacts for routine transportation, storage, and use of ammonia for PR 1109.1. The December 2015 Final PEA for NOx RECLAIM also concluded significant ammonia impacts, and the proposed project increases the severity of the previous analysis due to more installations and operation of SCR and SCR upgrades.	• The significance conclusions of the No Project Alternative would rely on those for the December 2015 Final PEA for NOx RECLAIM. • Significant impact for routine transportation, storage, and use of ammonia	• Same as proposed project	• Same as proposed project	• Same as proposed project

Table 5.4-2 (concluded)
Comparison of Adverse Environmental Impacts of the <u>Proposed Project and</u> Alternatives

Environmental Topic Area	Proposed Project	Alternative A: No Project	Alternative B: More Stringent Proposed Project	Alternative C: Less Stringent Proposed Project	Alternative D: Limited Start-Up, Shutdown, Malfunction
Hydrology	• Increased use of water for fugitive dust suppression during construction by ~~1,658~~ <u>1,961</u> gal/day • Increased use of water for hydrotesting by ~~220,000~~ <u>286,000</u> gal/day • No increased water use for operating air pollution control equipment	• NOx reduction projects would be conducted according to the December 2015 Final PEA for NOx RECLAIM. Water demand would be the same as previously analyzed in the December 2015 Final PEA for NOx RECLAIM.	• Same as proposed project unless the tightened schedule causes more construction projects occurring on a given day	• Same as proposed project or less amount of water for fugitive dust suppression on a peak day • Same as proposed project or less amount of water for hydrotesting on a peak day • Same as proposed project for operating air pollution control devices	• Same as proposed project
Hydrology Impacts Significant?	• Less than significant water demand impacts fugitive dust suppression during construction • Significant water demand impacts during hydrotesting: While the calculations show less than significant water demand impacts for hydrotesting for PR 1109.1, both the December 2015 Final PEA for NOx RECLAIM concluded significant water demand impacts for hydrotesting • Significant water use for operating air pollution control equipment: While the calculations show no increase in water use for operating air pollution control equipment for PR 1109.1, both the December 2015 Final PEA for NOx RECLAIM concluded significant operational water demand impacts due to the potential operation of a wet gas scrubber	The following conclusions for hydrology are from the December 2015 Final PEA for NOx RECLAIM: • Less than significant for water demand during construction • Significant for water demand during hydrotesting (assuming entire demand is based on potable water)	• Same as proposed project	• Same as proposed project, even if there are fewer overlapping projects using water for fugitive dust suppression and hydrotesting on peak day	• Same as proposed project

5.5 ALTERNATIVES REJECTED AS INFEASIBLE

In accordance with CEQA Guidelines Section 15126.6(c), a CEQA document should identify any alternatives that were considered by the lead agency, but were rejected as infeasible during the scoping process and briefly explain the reasons underlying the lead agency's determination. Section 15126.6(c) also states that among the factors that may be used to eliminate alternatives from detailed consideration in a CEQA document are: 1) failure to meet most of the basic project objectives; 2) infeasibility; or, 3) inability to avoid significant environmental impacts.

As noted in Section 5.1, the range of feasible alternatives to the proposed project is limited by the nature of the proposed project and associated legal requirements. Similarly, the range of alternatives considered, but rejected as infeasible is also relatively limited. The following subsection identifies Alternative A and Equipment Electrification alternative to the proposed project, as being rejected due to infeasibility for the reasons explained in the following subsection.

5.5.1 Alternative A - No Project

CEQA documents typically assume that the adoption of a No Project alternative would result in no further action on the part of the project proponent or lead agency. For example, in the case of a proposed land use project such as a housing development, adopting the No Project alternative terminates further consideration of that housing development or any housing development alternative identified in the associated CEQA document. In that case, the existing setting would typically remain unchanged.

However, Alternative A would require further action since state law under AB 617 still requires a BARCT analysis to be conducted. A comprehensive BARCT analysis was conducted as part of the proposed project, and the conclusions from that BARCT analysis, such as the proposed NOx limits and the control technology needed to meet those limits, is not expected to change between Alternative A and the proposed project. The primary difference is that, without the proposed rule, affected facilities would presumably return to demonstrating compliance under the RECLAIM program. The BARCT analysis, as done in the past, would result in a "shave" of the facilities allocation that can be met with either installation of control equipment or surrendering RTCs.

The main objectives of the proposed project are to: 1) reduce NOx emissions from refinery equipment and transition these equipment that are currently permitted under the NOx RECLAIM program to a command-and-control regulatory structure; and 2) implement Control Measure CMB-05 by requiring affected equipment operating at RECLAIM or former RECLAIM facilities to comply with current BARCT in accordance with a implementation schedule for transitioning affected units NOx RECLAIM facilities to a command-and-control regulatory structure; and 3) comply with the BARCT requirements in accordance with AB 617.

Alternative A is infeasible because it does not meet the objectives of the project, does not comply with the approved control measure CMB-05 adopted and legally mandated in the 2016 AQMP, or comply with the Governing Board directive to transition facilities from RECLAIM program to a command-and-control regulatory structure.

The Board would need to amend the 2016 AQMP and have that amendment approved by EPA in order to implement this alternative. Moreover, this alternative is inconsistent with AB 617, which according to the legislative history was intended to prevent facilities from relying on RTCs to meet the new AB 617 BARCT requirements. CARB has submitted to South Coast AQMD a letter expressing the opinion that AB 617 does not all9w reliance on RTCs.

5.5.2 Equipment Electrification

Boilers at petroleum refineries are primarily operated with gaseous fuel to produce steam, but, in turn, generate NOx emissions. Electric boilers are commercially available that provide sustainability due to no direct air pollutant emissions as combustion byproducts. In practice, electric water heater technology has provided rapid heating and more consistent temperatures. Also, the installation costs of electric boilers are lower due to elimination of the operational need for fuel piping and storage, and vent paths. Other advantages include lower operation costs due to elimination of standby operation status as well as lowered frequency of start-up/shutdown operations and shorter warm-up duration at start-up. However, the use of generated electricity to power the electric boiler will result in air pollution from the emissions at power plants compared to ones generated by burning fossil fuels in traditional boilers. Alternatively, one could electrify a steam turbine that is powered by a boiler, thus potentially eliminating the need for the boiler along with corresponding NOx emissions. In addition, process trains (such as compressors, blowers or pumps) are typically driven by a gas or steam turbine, and replacing old turbines with an electric system would eliminate previous NOx emissions from the turbines as well as increase process efficiency, lowering operational costs, etc. This alternative seeks ways to require electrification of equipment to not just lower NOx emissions but eliminate them. However, this alternative needs to consider construction necessary for infrastructure and possible demolition of existing equipment to make space, thus potentially not reducing the air quality impacts from construction compared to the proposed project. In addition, the technical feasibility of equipment electrification at this time and which equipment category could be considered applicable would need to be considered. Finally, the Health and Safety Code allows air pollution control districts to implement alternative methods of emission reduction [Health and Safety Code Section 40001(d)(2)], so requiring a particular technology such as electric equipment to replace equipment that combust fuels would not be feasible. In addition, Health and Safety Code Section 40001(d)(3) states: "If a district rule specifies an emission limit for a facility or system, the district shall not set operational or effectiveness requirements for any specific emission control equipment operating on a facility or system under that limit." So while facilities would not be precluded from electrifying equipment in order to meet the emission limits in PR 1109.1, to prescribe electric equipment to replace equipment that combust fuels would potentially conflict with these requirements in the Health and Safety Code. To avoid potential conflict, this alternative is rejected as infeasible.

5.6 LOWEST TOXIC AND ENVIRONMENTALLY SUPERIOR ALTERNATIVE

5.6.1 Lowest Toxic Alternative

In accordance with South Coast AQMD's policy document: Environmental Justice Program Enhancements for FY 2002-03, Enhancement II-1 recommends for all South Coast AQMD CEQA documents which are required to include an alternatives analysis, the alternative analysis shall also include and identify a feasible project alternative with the lowest air toxics emissions. In other words, for any major equipment or process type under the scope of the proposed project that creates a significant environmental impact, at least one alternative, where feasible, shall be considered from a "least harmful" perspective with regard to hazardous or toxic air pollutants.

As explained in Subchapter 4.3 – Hazards and Hazardous Materials, implementation of the proposed project may alter the hazards and hazardous materials associated with the existing facilities affected by the proposed project. Air pollution control equipment and related devices are expected to be installed or modified at affected facilities such that their operations may increase the quantity of materials used in the control equipment, some of which are hazardous. The main NOx reduction technology considered for the proposed project is SCR, which would increase the use of ammonia, a hazardous chemical.

In identifying a lowest toxic alternative with respect to the proposed project, because the types and quantities of required NOx controls installed will ultimately be the same, the lowest toxic alternative would be the one having the least amount of toxics being used simultaneously within a given time frame. Alternative A (No Project) could result in less hazardous materials overall only if control technology is not installed to comply with the BARCT analysis, but this alternative is rejected as infeasible as explained previously. Alternative B would utilize the same quantity of hazardous materials as the proposed project, even though the implementation schedule of Alternative B could cause air pollution control equipment to be installed and operated sooner. Alternative C will utilize the same quantity of hazardous materials as the proposed project even though the implementation schedule of Alternative C could delay the timing for the when the air pollution control equipment is installed and operated if facility operators implement the I-Plan option. Alternative D would utilize the same quantity of hazardous materials as the proposed project except during SSM events when air pollution control equipment is offline. Since the duration of allowed SSM events will be shorter under Alternative D when compared to the proposed project, once air pollution control equipment return to service, which will be sooner for Alternative D, the resumed use of ammonia will also occur sooner. For this reason, Alternative D may utilize slightly more ammonia than the proposed project when SCRs and UltraCat™ with DGS resume operation after an SSM event.

Thus, from a hazards and air toxics perspective, when compared to the proposed project and the other alternatives under consideration, if implemented, Alternative C is considered to be the lowest toxic alternative because of the amounts of hazardous materials that would be used as well as a delayed implementation.

5.6.2 Environmentally Superior Alternative

Pursuant to CEQA Guidelines Section 15126.6(e)(2), if the environmentally superior alternative is the No Project alternative, the CEQA document shall also identify an alternate environmentally superior alternative from among the other alternatives.

Under Alternative A (No Project), as allowed by NOx RECLAIM, facilities could opt to surrender NOx RTCs in lieu of installing and operating control technologies to comply with the BARCT requirements. Since, to date, the majority of facilities in NOx RECLAIM surrendered NOx RTCs with only nine projects resulting in NOx emission reductions of two to three tons per day from installing NOx control equipment, the no project alternative will not be expected to achieve the same amount of NOx emission reductions when compared to the proposed project. Therefore, Alternative A is not the environmentally superior alternative.

The proposed project's NOx emission reduction benefits should be the same for Alternatives B, C, and D, but with nuanced differences. Alternative B would generate the same quantity of NOx emission reductions as the proposed project, but with 0.37 tpd of NOx emission reductions from boilers and heaters < 40 MMBTU/hr achieved sooner than proposed project.

Alternative C is also expected to achieve the same quantity of NOx emission reductions overall as the proposed project, but with fewer incremental NOx emission reductions occurring early in Phases I and II for each I-Plan option. 100% of the NOx emission reductions will be achieved by Phase III in 2034, but the incremental NOx emissions reductions occurring early in Phases I and II cannot be quantified at this time.

Alternative D is also expected to have the same quantity of NOx emission reductions overall as the proposed project, but reducing the time allowed for SSM events by 50% for the same equipment categories as the proposed project, except for gas turbines. This could further limit NOx emissions when air pollution control equipment is offline. However, because SSM events are intermittent and cannot be predicted, the quantity of NOx emissions occurring during SSM events cannot be reliably quantified, only estimated to be 50 percent less for Alternative D than what would occur under the proposed project.

While Alternative D may have fewer NOx emissions occurring intermittently during SSM events when compared to the proposed project, Alternative B would generate permanent NOx emission reductions, with a portion occurring sooner than the proposed project. Thus, Alternative B would be considered the environmentally superior alternative.

5.7 CONCLUSION

As discussed previously, Alternative A would not fulfill the objectives of the proposed project, or comply with AB 617, and thus was considered infeasible. Alternatives B, C, and D would all be expected to generate equivalent or similar impacts to proposed project in all environmental topic areas analyzed. Alternative B would achieve slightly more emission reductions sooner. Alternative C would achieve the same reductions as the proposed project, but at a later date. Alternative D would achieve the same reductions as the proposed project but would limit emissions during SSM events for which the benefit cannot be predicted or quantified at this time. Thus, the proposed project is considered to provide the best balance between emission reductions and the adverse environmental impacts due to construction and operation activities while meeting the overall objectives. Therefore, the proposed project best balances achieving the project objectives and the potential adverse impacts.

CHAPTER 6

REFERENCES

6.0 References

The December 2015 Final PEA for NOx RECLAIM and the March 2017 Final Program EIR for the 2016 AQMP, upon which this SEA relies, are incorporated by reference pursuant to CEQA Guidelines Section 15150 and are available from the South Coast AQMD's website at:

December 2015 Final PEA and October 2016 Addendum for NOx RECLAIM:
http://www.aqmd.gov/home/research/documents-reports/lead-agency-scaqmd-projects/scaqmd-projects---year-2015

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Chapter 1 – Executive Summary

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2. The CEQA Guidelines are codified at Title 14 California Code of Regulations Section 15000 et seq.
3. Health and Safety Code Section 40460(a).
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7. South Coast AQMD, Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), SCH No. 2014121018/SCAQMD No. 12052014BAR, certified December 4, 2015. http://www.aqmd.gov/home/library/documents-support-material/lead-agency-scaqmd-projects/scaqmd-projects---year-2015.
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12. South Coast AQMD, Final Subsequent Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM): Proposed Amended Rule 2001 – Applicability, and Proposed Amended Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx), October 2018. http://www.aqmd.gov/docs/defaultsource/ceqa/documents/aqmd-projects/2018/finalseaforpars2001-2002-fullmerge.pdf.
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14. South Coast AQMD, Final Subsequent Environmental Assessment for Proposed Amended Rules 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters; 1146.1 – Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters; 1146.2 - Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters; and Proposed Rule 1100 – Implementation Schedule for NOx Facilities, November 2018. http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2018/pars-1146-series---final-sea---full-merge-113018.pdf.
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18. 40 CFR 51.165(h)(2) and 40 CFR 52.21(cc)(2) are the vacated provisions that defined basic design parameters
19. The definitions of functionally equivalent component and basic design parameters were vacated. However, even though these definitions were removed, they can still be used as guidance to define replacements. See 86 FR 37918 stating: “However, while not controlling, the EPA and stakeholders may continue to look to the vacated definitions from the ERP rule to guide their understanding of the definition of replacement unit.”

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CHAPTER 7

ACRONYMS

7.0 ACRONYMS

ABBREVIATION = DESCRIPTION

μg/m^3 = micrograms per cubic meter
ABS = Ammonium Bisulfate
ACGIH = American Conference of Governmental Industrial Hygiene
APS = Alternative Planning Strategy
AQMP = Air Quality Management Plan
ASC = Ammonia Slip Catalyst
ASME = American Society of Mechanical Engineers
ATCM = Airborne Toxic Control Measure
ATCP = Air Toxics Control Plan
B100 = biodiesel
B-CAP = BARCT Equivalent Mass Cap Plan
BACM = Best Available Control Measure
BACT = Best Available Control Technology
BARCT = Best Available Retrofit Control Technology
Basin = South Coast Air Basin
BAU = business-as-usual
BLEVE = boiling liquid expanding vapor explosion
BLM = Bureau of Land Management
BMP = best management practice
C3H8 = propane
CAA = Clean Air Act
CAFE = Corporate Average Fuel Economy
CalARP = California Accidental Release Prevention Program
CalEMA = California Emergency Management Agency
CalEPA = California Environmental Protection Agency
CalOSHA = California Occupational Safety and Health Administration
Caltrans = California Department of Transportation
CaOH = calcium hydroxide
CAPCOA = California Air Pollution Control Officers Association
CARB = California Air Resources Board
CCAR = California Climate Action Registry
CCP = Clean Communities Plan
CCR = California Code of Regulations
CEC = California Energy Commission
CEMS = continuous emissions monitor system
CEQA = California Environmental Quality Act
CERCLA = Comprehensive Environmental Response, Compensation, and Liability Act
CERs = Certified Emission Reductions
CFR = Code of Federal Regulations

CH4 = methane
CHMIRS = California Hazardous Materials Incident Reporting System
CHP = California Highway Patrol
CIP = Capital Improvement Program
CIWMP = Countrywide Integrated Waste Management Plan
CM = control measure
CMA = Congestion Management Agency
CNG = compressed natural gas
CO = carbon monoxide
CO2 = carbon dioxide
CO2eq = carbon dioxide equivalent
COD = chemical oxygen demand
COHb = carboxyhemoglobin
CPCC = California Portland Cement Company
CPSC = Consumer Products Safety Commission
CPUC = California Public Utilities Commission
CRA = Colorado River Aqueduct
CS2 = carbon disulfide
CUPA = Certified Unified Program Agency
CWA = Clean Water Act
CWAP = Clean Water Action Plan
CY = Compliance Year
DC = direct current
DCF = Discounted Cash Flow
DEA = diethanolamine
DFW = Department of Fish and Wildlife
DGS = dry gas scrubber
DHS = Department of Health Services
DLN/DLE = Dry Low NOx/Dry Low Emissions
DPH = Department of Public Heath
DTSC = Department of Toxic Substance Control
DWR = California Department of Water Resources
EA = Environmental Assessment
EAP = Emergency Action Plan
EDV = Electro Dynamic Venturi
EGF = electric generating facility
EIR = Environmental Impact Report
EISA = Energy Independence and Security Act
EJ = Environmental Justice
EJAG = Environmental Justice Advisory Group
EMWD = Eastern Municipal Water District
ERPG = Emergency Response Planning Guidelines
°F = Degree Fahrenheit

FCCU = fluid catalytic cracking unit
Fe203 = iron oxide
FedOSHA = Federal Occupational Safety and Health Administration
FEMA = Federal Emergency Management Agency
FFV = flexible fuel vehicle
FGT = fuel gas treatment
FHWA = Federal Highway Administration
FR = Federal Register
FUA = Fuel Use Act
gal = gallons
GC/TCD = Gas Chromatograph-Thermal Conductivity Detector
GF = Growth Factor
GHG = greenhouse gases
GHGRP = Greehouse Gas Reporting Program
gWh = gigawatt-hour
GWP = global warming potential
H2S = hydrogen sulfide
H2SO4 = sulfuric acid
HAP = hazardous air pollutant
HCFC = hydrochlorofluorocarbon
HCl = hydrochloric acid
HDRD = hydrogeneration-derived renewable diesel
HF = hydrofluoric acid
HHV = High Heating Value of Fuel
HMTA = Hazardous Material Transportation Act
HOV = high occupancy vehicle
HRSG = heat recovery steam generation
HSC = Health and Safety Code
HWCL = Hazardous Waste Control Law
ICE = internal combustion engines
IDLH = Immediately Dangerous to Life and Health
inH20 = inches water column
IRP = Integrated Water Resources Plan
IS = Initial Study
kW = kilowatt
kWh = kilowatt-hour
LAA = Los Angeles Aqueduct
LACSD = Los Angeles County Sanitation District
LADWP = Los Angeles Department of Water and Power
LAER = Lowest Achievable Emission Rate
LCFS = Low Carbon Fuel Standard
LCP = Local Coastal Program
LEA = Local Enforcement Agencies

LEED = Leadership in Energy and Environmental Design
LEL = lower explosive limit
LEPC = Local Emergency Planning Committee
LNB = Low NOx Burner
LOS = level of service
LoTOx™ = Low Temperature Oxidation Process for NOx Control
LPG = liquefied petroleum gas
LRP = Local Resources Program
LTCP = Long-Term Conservation Plan
LUP = land use plan
M&I = municipal and industrial
MATES = Multiple Air Toxics Exposure Studies
MCL = Maximum Contaminant Levels
MDAB = Mojave Desert Air Basin
mmBTU or MMBTU = metric million British Thermal Units
MMscf = Million Standard Cubic Feet
MoO3 = molybdic anhydride
MPO = Metropolitan Planning Organization
MS4s = municipal separate storm sewer systems
MSBACT = Minor Source Best Available Control Technology
MTBE = methyl tertiary butyl ether
MW = megawatt
MWD = Metropolitan Water District
N2O = nitrous oxide
Na2CO3 = sodium carbonate
Na2S2O5 = sodium pyrosulfate
Na2SO3 = sodium sulfite
NAAQS = National Ambient Air Quality Standards
NaHSO3 = sodium bisulfite
NaOH = sodium hydroxide
NCP = National Contingency Plan
NEC = Norton Engineering Consultants Inc.
NECPA = National Energy Conservation Policy Act
NESHAP = National Emission Standard for Hazardous Air Pollutants
NFC = National Fire Code
NFPA = National Fire Protection
NG = Natural Gas
NH03 = nitric oxide
NH3 = ammonia
NHTSA = National Highway Traffic and Safety Administration
NIOSH = National Institute for Occupational Safety and Health
NO = nitric oxide
NO2 = nitrogen dioxide
NOP/IS = Notice of Preparation/Initial Study

NOx = oxides of nitrogen
NPDES = National Pollutant Discharge Elimination System
NSCR = non-selective catalytic reduction
NSR = New Source Review
O2 = oxygen
O3 = ozone
OCHCA = Orange County Health Care Agency
OCS = outer continental shelf
OCTA = Orange County Transportation Authority
ODS = ozone depleting substance
OEHA = Office of Environmental Health Hazard Assessment
OES = Office of Emergency Services
OHMS = Office of Hazardous Materials Safety
OPR = Office of Planning and Research
OSHA = Occupational Safety and Health Administration
PAR = Proposed Amended Rule
PCU = publicly owned utilities
PEA = Program Environmental Assessment
PEL = permissible exposure limit
PEV = plug-in electric vehicle
PFC = perfluorocarbon
PM = particulate matter
PM10 = particulate matter with an aerodynamic diameter of 10 microns or less
PM2.5 = particulate matter with an aerodynamic diameter of 2.5 microns or less
ppm = parts per million
ppmv = parts per million by volume
PR = Proposed Rule
PSA = Pressure Swing Adsorption
PSD = Prevention of Significant Deterioration
PSM = Process Safety Management
PURPA = Public Utilities Regulatory Policies Act
PV = photovoltaic
Qfs = qualifying facilities
QSA = Quantification Settlement Agreement
QV = qualified vehicle testers
RCRA = Resource Conservation and Recovery Act
RECLAIM = Regional Clean Air Incentives Market
REL = Reference Exposure Level
RFG = Refinery Fuel Gas
RFS = renewable fuel standard
RIN = renewable identification number
RMP = Risk Management Programs
RPS = renewables portfolio standard

RTAC = Regional Target Advisory Committee
RTC = RECLAIM Trading Credit
RTIP = Regional Transportation Improvement Program
RTP = Regional Transportation Plan
RWQCB = Regional Water Quality Control Board
SCAB = South Coast Air Basin
SCAG = Southern California Association of Governments
South Coast AQMD = South Coast Air Quality Management District
SCE = Southern California Edison
SCHWMA = Southern California Hazardous Waste Management Authority
SCR = selective catalytic reduction
SCS = sustainable communities strategy
SEA = Supplemental Environmental Assessment
SF6 = sulfur hexafluoride
SI = spark ignited
SIP = State Implementation Plan
SMR = Steam Methane Reformer
SNCR = selective non-catalytic reduction
SO2 = sulfur dioxide
SO3 = sulfur trioxide
SoCal Gas = Southern California Gas Company
SOx = oxides of sulfur
SRRE = Source Reduction and Recycling Element
SRU/TGU = sulfur recovery unit/tail gas unit
SSAB = Salton Sea Air Basin
STEL = short-term exposure limits
SWMP = Storm Water Management Plan
SWP = State Water Project
SWPPP = Storm Water Pollution Prevention Plan
SWRCB = State Water Resources Control Board
TDM = Transportation Demand Management
TEA-21 = Transportation Equity Act for the 21st Century
TLVs = Threshold Limit Values
tons/day = tons per day
tpd = tons per day
TRI = Toxic Release Inventory
TSCA = Toxic Substances Control Act
TSS = total suspended solids
TWA = time-weighted average
UEL = upper explosive limt
ULNB = Ultra-Low NOx Burner
UltraCat™ = UltraCat™ Catalyst Filter Manufactured by Tri-Mer Corporation
USC = United States Code

U.S. DOE = United States Department of Energy

U.S. DOT = United States Department of Transportation

U.S. EPA = United States Environmental Protection Agency

USFS = United States Forest Service

V_2O_5 = vanadium pentoxide

VMT = vehicle miles of travel

VOC = volatile organic compound(s)

WCI = Western Climate Incentive

WDR = waste discharge requirements

WHB = waste heat boiler

WGM = Working Group Meeting

WGS = wet gas scrubber

WSPA = Western States Petroleum Association

APPENDICES

Appendix A1: Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations

Appendix A2: Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations

Appendix A3: Proposed Amended Rule 1304 – Exemptions

Appendix A4: Proposed Amended Rule 2005 – New Source Review for RECLAIM

Appendix A5: Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries

Appendix B: CalEEMod® Files

Appendix C: CEQA Impact Calculations

Appendix D: List of Affected Facilities and Equipment

Appendix E: Off-site Consequence, Ammonia Slip, and PM2.5 Concentration Analyses

Appendix F: Comment Letters Received on the Draft SEA and Responses to Comments

APPENDIX A1

Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations

In order to save space and avoid repetition, please refer to the latest version of PR 1109.1 located elsewhere in the Governing Board Package (meeting date November 5, 2021). The version of PR 1109.1 that was circulated with the Draft SEA for a 46-day public review and comment period which was released on September 3, 2021 and ending on October 19, 2021 was identified as the "Preliminary Draft Rule PR 1109.1, revision date August 20, 2021", which is available from the South Coast AQMD's website at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pd_pr1109-1_75_day.pdf. An original hard copy of the Draft SEA, which included the draft version of PR 1109.1 listed above, can be obtained through the South Coast AQMD Public Information Center by phone at (909) 396-2001 or by email at PICrequests@aqmd.gov.

APPENDIX A2

Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations

In order to save space and avoid repetition, please refer to the latest version of PR 429.1 located elsewhere in the Governing Board Package (meeting date November 5, 2021). The version of PR 429.1 that was circulated with the Draft SEA for a 46-day public review and comment period which was released on September 3, 2021 and ending on October 19, 2021 was identified "Version 081821", which is available from the South Coast AQMD's website at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/429.1/rule-429-1-pdrl-pw.pdf. An original hard copy of the Draft SEA, which included the draft version of PR 429.1 listed above, can be obtained through the South Coast AQMD Public Information Center by phone at (909) 396-2001 or by email at PICrequests@aqmd.gov.

APPENDIX A3

Proposed Amended Rule 1304 – Exemptions

In order to save space and avoid repetition, please refer to the latest version of PAR 1304 located elsewhere in the Governing Board Package (meeting date November 5, 2021). The version of PAR 1304 that was circulated with the Draft SEA for a 46-day public review and comment period which was released on September 3, 2021 and ending on October 19, 2021 was identified "Version 08-17-2021", which is available from the South Coast AQMD's website at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/par-1304-and-par-2005/par-1304-preliminary-draft-rule-language-aug-2021.pdf. An original hard copy of the Draft SEA, which included the draft version of PAR 1304 listed above, can be obtained through the South Coast AQMD Public Information Center by phone at (909) 396-2001 or by email at PICrequests@aqmd.gov.

APPENDIX A4

Proposed Amended Rule 2005 – New Source Review for RECLAIM

In order to save space and avoid repetition, please refer to the latest version of PAR 2005 located elsewhere in the Governing Board Package (meeting date November 5, 2021). The version of PAR 2005 that was circulated with the Draft SEA for a 46-day public review and comment period which was released on September 3, 2021 and ending on October 19, 2021 was identified "Version 08-17-2021", which is available from the South Coast AQMD's website at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/par-1304-and-par-2005/par-2005-preliminary-draft-rule-language-aug-2021.pdf. An original hard copy of the Draft SEA, which included the draft version of PAR 2005 listed above, can be obtained through the South Coast AQMD Public Information Center by phone at (909) 396-2001 or by email at PICrequests@aqmd.gov.

APPENDIX A5

Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries

In order to save space and avoid repetition, please refer to the latest version of proposed rescinded Rule 1109 located elsewhere in the Governing Board Package (meeting date November 5, 2021). The version of proposed rescinded Rule 1109 that was circulated with the Draft SEA for a 46-day public review and comment period which was released on September 3, 2021 and ending on October 19, 2021 is available from the South Coast AQMD's website at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/prr1109---rescission.pdf. An original hard copy of the Draft SEA, which included the draft version of proposed rescinded Rule 1109 listed above, can be obtained through the South Coast AQMD Public Information Center by phone at (909) 396-2001 or by email at PICrequests@aqmd.gov.

APPENDIX B

CalEEMod® Files

Replace LNB with ULNB
Los Angeles-South Coast County, Annual

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
General Heavy Industry	0.10	1000sqft	0.00	100.00	0

1.2 Other Project Characteristics

Urbanization Urban **Wind Speed (m/s)** 2.2 **Precipitation Freq (Days)** 33

Climate Zone 11 **Operational Year** 2021

Utility Company Los Angeles Department of Water & Power

CO2 Intensity (lb/MWhr) 1227.89 **CH4 Intensity (lb/MWhr)** 0.029 **N2O Intensity (lb/MWhr)** 0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics -

Land Use - Per Rule Team estimate, foudation for fuel gas cleaning vessel might be 10 ft x 10 ft

Construction Phase - Conservatively assumed there is an existing coalescer vessel to be replaced by a new one. Per John Zink Company, installing 100 burners will take 3 months - a given heater affected by R1109.1 will likely have less burners.

Off-road Equipment - Equipment estimated by Rule team. A tractors/loaders/backhoes is used to represent skip loader.

Off-road Equipment - Off-highway trucks is representing concrete mixing/transportation truck. Coalescer vessel footprint is about 10 ft x 10 ft.

Off-road Equipment - Equipment estimated by rule team. A tractors/loaders/backhoes is used to represent skip loader.

Off-road Equipment - Equipment estimated by Rule team. One of the tractors/loaders/backhoes is used to represent skip loader.

Off-road Equipment - Estimated by rule team.

Trips and VMT - Trips estimated after consultation with Rule team.

Vehicle Emission Factors -

Vehicle Emission Factors -

Vehicle Emission Factors -

Construction Off-road Equipment Mitigation - Assume all equipment that is 50 hp or bigger will need to be Tier 4 Final.

Fleet Mix -

Table Name	Column Name	Default Value	New Value
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	3.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	3.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	4.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	2.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	4.00
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstructionPhase	NumDays	0.00	5.00
tblConstructionPhase	NumDays	0.00	1.00
tblConstructionPhase	NumDays	0.00	92.00
tblConstructionPhase	NumDays	0.00	1.00
tblConstructionPhase	NumDays	0.00	14.00
tblConstructionPhase	NumDaysWeek	5.00	7.00
tblConstructionPhase	NumDaysWeek	5.00	7.00
tblConstructionPhase	NumDaysWeek	5.00	7.00
tblConstructionPhase	NumDaysWeek	5.00	7.00
tblConstructionPhase	NumDaysWeek	5.00	7.00
tblOffRoadEquipment	OffRoadEquipmentType		Generator Sets
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	4.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	UsageHours	6.00	4.00

tblOffRoadEquipment	UsageHours	4.00	24.00
tblOffRoadEquipment	UsageHours	4.00	12.00
tblOffRoadEquipment	UsageHours	6.00	24.00
tblOffRoadEquipment	UsageHours	6.00	12.00
tblOffRoadEquipment	UsageHours	8.00	2.00
tblOffRoadEquipment	UsageHours	8.00	12.00
tblOffRoadEquipment	UsageHours	6.00	12.00
tblTripsAndVMT	HaulingTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripNumber	0.00	16.00
tblTripsAndVMT	VendorTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripNumber	0.00	8.00
tblTripsAndVMT	WorkerTripNumber	13.00	10.00
tblTripsAndVMT	WorkerTripNumber	13.00	0.00
tblTripsAndVMT	WorkerTripNumber	3.00	8.00
tblTripsAndVMT	WorkerTripNumber	0.00	20.00
tblTripsAndVMT	WorkerTripNumber	5.00	4.00
tblTripsAndVMT	WorkerTripNumber	0.00	10.00

2.0 Emissions Summary

2.1 Overall Construction

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2021	0.1977	1.8795	1.5568	3.2100e-003	0.0166	0.0919	0.1084	4.5000e-003	0.0880	0.0925	0.0000	280.6949	280.6949	0.0471	0.0000	281.8735
Maximum	**0.1977**	**1.8795**	**1.5568**	**3.2100e-003**	**0.0166**	**0.0919**	**0.1084**	**4.5000e-003**	**0.0880**	**0.0925**	**0.0000**	**280.6949**	**280.6949**	**0.0471**	**0.0000**	**281.8735**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2021	0.0418	0.2359	1.7322	3.2100e-003	0.0165	5.2600e-003	0.0218	4.5000e-003	5.2500e-003	9.7500e-003	0.0000	280.6947	280.6947	0.0471	0.0000	281.8732
Maximum	**0.0418**	**0.2359**	**1.7322**	**3.2100e-003**	**0.0165**	**5.2600e-003**	**0.0218**	**4.5000e-003**	**5.2500e-003**	**9.7500e-003**	**0.0000**	**280.6947**	**280.6947**	**0.0471**	**0.0000**	**281.8732**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**78.87**	**87.45**	**-11.27**	**0.00**	**0.18**	**94.27**	**79.90**	**0.00**	**94.04**	**89.46**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Quarter	**Start Date**	**End Date**	**Maximum Unmitigated ROG + NOX (tons/quarter)**	**Maximum Mitigated ROG + NOX (tons/quarter)**
1	**6-7-2021**	**9-6-2021**	2.0755	0.2759
		Highest	2.0755	0.2759

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	4.1000e-004	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Energy	1.0000e-005	9.0000e-005	7.0000e-005	0.0000		1.0000e-005	1.0000e-005		1.0000e-005	1.0000e-005	0.0000	0.7148	0.7148	2.0000e-005	0.0000	0.7167
Mobile	6.0000e-005	3.1000e-004	8.7000e-004	0.0000	2.5000e-004	0.0000	2.5000e-004	7.0000e-005	0.0000	7.0000e-005	0.0000	0.2858	0.2858	1.0000e-005	0.0000	0.2862
Waste						0.0000	0.0000		0.0000	0.0000	0.0244	0.0000	0.0244	1.4400e-003	0.0000	0.0604
Water						0.0000	0.0000		0.0000	0.0000	7.3400e-003	0.1677	0.1750	7.6000e-004	2.0000e-005	0.1995
Total	**4.8000e-004**	**4.0000e-004**	**9.4000e-004**	**0.0000**	**2.5000e-004**	**1.0000e-005**	**2.6000e-004**	**7.0000e-005**	**1.0000e-005**	**8.0000e-005**	**0.0317**	**1.1683**	**1.2000**	**2.2300e-003**	**2.0000e-005**	**1.2627**

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	4.1000e-004	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Energy	1.0000e-005	9.0000e-005	7.0000e-005	0.0000		1.0000e-005	1.0000e-005		1.0000e-005	1.0000e-005	0.0000	0.7148	0.7148	2.0000e-005	0.0000	0.7167
Mobile	6.0000e-005	3.1000e-004	8.7000e-004	0.0000	2.5000e-004	0.0000	2.5000e-004	7.0000e-005	0.0000	7.0000e-005	0.0000	0.2858	0.2858	1.0000e-005	0.0000	0.2862
Waste						0.0000	0.0000		0.0000	0.0000	0.0244	0.0000	0.0244	1.4400e-003	0.0000	0.0604
Water						0.0000	0.0000		0.0000	0.0000	7.3400e-003	0.1677	0.1750	7.6000e-004	2.0000e-005	0.1995
Total	**4.8000e-004**	**4.0000e-004**	**9.4000e-004**	**0.0000**	**2.5000e-004**	**1.0000e-005**	**2.6000e-004**	**7.0000e-005**	**1.0000e-005**	**8.0000e-005**	**0.0317**	**1.1683**	**1.2000**	**2.2300e-003**	**2.0000e-005**	**1.2627**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Demolition of existing Fuel Gas Cleaning Vessel	Demolition	6/7/2021	6/11/2021	7	5	
2	Scaffold Installation	Site Preparation	6/7/2021	6/7/2021	7	1	
3	Burner Replacement	Building Construction	6/7/2021	9/6/2021	7	92	
4	Concrete Pour -Fuel Gas Cleaning Vessel Foundation	Paving	6/12/2021	6/12/2021	7	1	
5	Install Fuel Gas Cleaning Vessel	Building Construction	6/13/2021	6/26/2021	7	14	

Acres of Grading (Site Preparation Phase): 0

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0; Striped Parking Area: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Demolition of existing Fuel Gas Cleaning Vessel	Air Compressors	1	12.00	78	0.48
Demolition of existing Fuel Gas Cleaning Vessel	Cranes	1	12.00	231	0.29
Demolition of existing Fuel Gas Cleaning Vessel	Forklifts	1	12.00	89	0.20
Demolition of existing Fuel Gas Cleaning Vessel	Tractors/Loaders/Backhoes	1	12.00	97	0.37
Scaffold Installation	Forklifts	1	12.00	89	0.20
Burner Replacement	Air Compressors	1	24.00	78	0.48
Burner Replacement	Cranes	1	24.00	231	0.29
Burner Replacement	Forklifts	1	24.00	89	0.20
Burner Replacement	Generator Sets	1	24.00	84	0.74
Burner Replacement	Tractors/Loaders/Backhoes	1	2.00	97	0.37
Concrete Pour -Fuel Gas Cleaning Vessel Foundation	Cement and Mortar Mixers	1	4.00	9	0.56
Concrete Pour -Fuel Gas Cleaning Vessel Foundation	Off-Highway Trucks	1	4.00	402	0.38
Install Fuel Gas Cleaning Vessel	Air Compressors	1	13.00	78	0.48
Install Fuel Gas Cleaning Vessel	Bore/Drill Rigs	1	12.00	221	0.50
Install Fuel Gas Cleaning Vessel	Cranes	1	12.00	231	0.29
Install Fuel Gas Cleaning Vessel	Forklifts	1	12.00	89	0.20
Install Fuel Gas Cleaning Vessel	Tractors/Loaders/Backhoes	2	12.00	97	0.37
Install Fuel Gas Cleaning Vessel	Welders	1	12.00	46	0.45
Demolition of existing Fuel Gas Cleaning Vessel	Generator Sets	1	12.00	84	0.74

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Demolition of existing Fuel Gas Cleaning Vessel	5	10.00	2.00	2.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Demolition of existing Fuel Gas Cleaning Vessel	5	0.00	0.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Scaffold Installation	1	8.00	2.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Burner Replacement	5	20.00	16.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Concrete Pour -Fuel Gas Cleaning Vessel Foundation	2	4.00	2.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Install Fuel Gas Cleaning Vessel	7	10.00	8.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Use Cleaner Engines for Construction Equipment

Water Exposed Area

3.2 Demolition of existing Fuel Gas Cleaning Vessel - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					5.0000e-005	0.0000	5.0000e-005	1.0000e-005	0.0000	1.0000e-005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	5.1700e-003	0.0492	0.0432	8.0000e-005		2.5700e-003	2.5700e-003		2.4500e-003	2.4500e-003	0.0000	6.8242	6.8242	1.3000e-003	0.0000	6.8568
Total	**5.1700e-003**	**0.0492**	**0.0432**	**8.0000e-005**	**5.0000e-005**	**2.5700e-003**	**2.6200e-003**	**1.0000e-005**	**2.4500e-003**	**2.4600e-003**	**0.0000**	**6.8242**	**6.8242**	**1.3000e-003**	**0.0000**	**6.8568**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	1.0000e-005	2.8000e-004	6.0000e-005	0.0000	3.0000e-005	0.0000	3.0000e-005	1.0000e-005	0.0000	1.0000e-005	0.0000	0.0762	0.0762	1.0000e-005	0.0000	0.0764
Vendor	2.0000e-005	4.9000e-004	1.3000e-004	0.0000	5.0000e-005	0.0000	5.0000e-005	1.0000e-005	0.0000	2.0000e-005	0.0000	0.1233	0.1233	1.0000e-005	0.0000	0.1234
Worker	1.1000e-004	8.0000e-005	9.5000e-004	0.0000	5.1000e-004	0.0000	5.1000e-004	1.3000e-004	0.0000	1.3000e-004	0.0000	0.2472	0.2472	1.0000e-005	0.0000	0.2474
Total	**1.4000e-004**	**8.5000e-004**	**1.1400e-003**	**0.0000**	**5.9000e-004**	**0.0000**	**5.9000e-004**	**1.5000e-004**	**0.0000**	**1.6000e-004**	**0.0000**	**0.4467**	**0.4467**	**3.0000e-005**	**0.0000**	**0.4472**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e

Category	tons/yr										MT/yr					
Fugitive Dust					2.0000e-005	0.0000	2.0000e-005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	8.7000e-004	3.7900e-003	0.0473	8.0000e-005		1.2000e-004	1.2000e-004		1.2000e-004	1.2000e-004	0.0000	6.8242	6.8242	1.3000e-003	0.0000	6.8568
Total	**8.7000e-004**	**3.7900e-003**	**0.0473**	**8.0000e-005**	**2.0000e-005**	**1.2000e-004**	**1.4000e-004**	**0.0000**	**1.2000e-004**	**1.2000e-004**	**0.0000**	**6.8242**	**6.8242**	**1.3000e-003**	**0.0000**	**6.8568**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	1.0000e-005	2.8000e-004	6.0000e-005	0.0000	3.0000e-005	0.0000	3.0000e-005	1.0000e-005	0.0000	1.0000e-005	0.0000	0.0762	0.0762	1.0000e-005	0.0000	0.0764
Vendor	2.0000e-005	4.9000e-004	1.3000e-004	0.0000	5.0000e-005	0.0000	5.0000e-005	1.0000e-005	0.0000	2.0000e-005	0.0000	0.1233	0.1233	1.0000e-005	0.0000	0.1234
Worker	1.1000e-004	8.0000e-005	9.5000e-004	0.0000	5.1000e-004	0.0000	5.1000e-004	1.3000e-004	0.0000	1.3000e-004	0.0000	0.2472	0.2472	1.0000e-005	0.0000	0.2474
Total	**1.4000e-004**	**8.5000e-004**	**1.1400e-003**	**0.0000**	**5.9000e-004**	**0.0000**	**5.9000e-004**	**1.5000e-004**	**0.0000**	**1.6000e-004**	**0.0000**	**0.4467**	**0.4467**	**3.0000e-005**	**0.0000**	**0.4472**

3.3 Scaffold Installation - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	1.0000e-004	8.8000e-004	8.8000e-004	0.0000		6.0000e-005	6.0000e-005		6.0000e-005	6.0000e-005	0.0000	0.1007	0.1007	3.0000e-005	0.0000	0.1015
Total	**1.0000e-004**	**8.8000e-004**	**8.8000e-004**	**0.0000**		**6.0000e-005**	**6.0000e-005**		**6.0000e-005**	**6.0000e-005**	**0.0000**	**0.1007**	**0.1007**	**3.0000e-005**	**0.0000**	**0.1015**

Unmitigated Construction Off-Site

Category	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	1.0000e-004	3.0000e-005	0.0000	1.0000e-005	0.0000	1.0000e-005	0.0000	0.0000	0.0000	0.0000	0.0247	0.0247	0.0000	0.0000	0.0247
Worker	2.0000e-005	1.0000e-005	1.5000e-004	0.0000	4.0000e-005	0.0000	4.0000e-005	1.0000e-005	0.0000	1.0000e-005	0.0000	0.0396	0.0396	0.0000	0.0000	0.0396
Total	**2.0000e-005**	**1.1000e-004**	**1.8000e-004**	**0.0000**	**5.0000e-005**	**0.0000**	**5.0000e-005**	**1.0000e-005**	**0.0000**	**1.0000e-005**	**0.0000**	**0.0642**	**0.0642**	**0.0000**	**0.0000**	**0.0643**

Mitigated Construction On-Site

Category	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	tons/yr										MT/yr					
Off-Road	1.0000e-005	6.0000e-005	8.7000e-004	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.1007	0.1007	3.0000e-005	0.0000	0.1015
Total	**1.0000e-005**	**6.0000e-005**	**8.7000e-004**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**0.1007**	**0.1007**	**3.0000e-005**	**0.0000**	**0.1015**

Mitigated Construction Off-Site

Category	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	1.0000e-004	3.0000e-005	0.0000	1.0000e-005	0.0000	1.0000e-005	0.0000	0.0000	0.0000	0.0000	0.0247	0.0247	0.0000	0.0000	0.0247
Worker	2.0000e-005	1.0000e-005	1.5000e-004	0.0000	4.0000e-005	0.0000	4.0000e-005	1.0000e-005	0.0000	1.0000e-005	0.0000	0.0396	0.0396	0.0000	0.0000	0.0396

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Total	**2.0000e-005**	**1.1000e-004**	**1.8000e-004**	**0.0000**	**5.0000e-005**	**0.0000**	**5.0000e-005**	**1.0000e-005**	**0.0000**	**1.0000e-005**	**0.0000**	**0.0642**	**0.0642**	**0.0000**	**0.0000**	**0.0643**

3.4 Burner Replacement - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	0.1666	1.5716	1.3037	2.5000e-003		0.0805	0.0805		0.0773	0.0773	0.0000	216.5992	216.5992	0.0368	0.0000	217.5201
Total	**0.1666**	**1.5716**	**1.3037**	**2.5000e-003**		**0.0805**	**0.0805**		**0.0773**	**0.0773**	**0.0000**	**216.5992**	**216.5992**	**0.0368**	**0.0000**	**217.5201**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	2.2900e-003	0.0726	0.0197	1.9000e-004	4.6400e-003	1.5000e-004	4.7800e-003	1.3400e-003	1.4000e-004	1.4800e-003	0.0000	18.1422	18.1422	1.1100e-003	0.0000	18.1700
Worker	3.9600e-003	3.0800e-003	0.0348	1.0000e-004	0.0101	8.0000e-005	0.0102	2.6800e-003	8.0000e-005	2.7500e-003	0.0000	9.0980	9.0980	2.7000e-004	0.0000	9.1047
Total	**6.2500e-003**	**0.0757**	**0.0545**	**2.9000e-004**	**0.0147**	**2.3000e-004**	**0.0149**	**4.0200e-003**	**2.2000e-004**	**4.2300e-003**	**0.0000**	**27.2402**	**27.2402**	**1.3800e-003**	**0.0000**	**27.2747**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Off-Road	0.0274	0.1186	1.4429	2.5000e-003		3.6500e-003	3.6500e-003		3.6500e-003	3.6500e-003	0.0000	216.5990	216.5990	0.0368	0.0000	217.5199
Total	**0.0274**	**0.1186**	**1.4429**	**2.5000e-003**		**3.6500e-003**	**3.6500e-003**		**3.6500e-003**	**3.6500e-003**	**0.0000**	**216.5990**	**216.5990**	**0.0368**	**0.0000**	**217.5199**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	2.2900e-003	0.0726	0.0197	1.9000e-004	4.6400e-003	1.5000e-004	4.7800e-003	1.3400e-003	1.4000e-004	1.4800e-003	0.0000	18.1422	18.1422	1.1100e-003	0.0000	18.1700
Worker	3.9600e-003	3.0800e-003	0.0348	1.0000e-004	0.0101	8.0000e-005	0.0102	2.6800e-003	8.0000e-005	2.7500e-003	0.0000	9.0980	9.0980	2.7000e-004	0.0000	9.1047
Total	**6.2500e-003**	**0.0757**	**0.0545**	**2.9000e-004**	**0.0147**	**2.3000e-004**	**0.0149**	**4.0200e-003**	**2.2000e-004**	**4.2300e-003**	**0.0000**	**27.2402**	**27.2402**	**1.3800e-003**	**0.0000**	**27.2747**

3.5 Concrete Pour -Fuel Gas Cleaning Vessel Foundation - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	1.7000e-004	1.4100e-003	9.8000e-004	0.0000		5.0000e-005	5.0000e-005		5.0000e-005	5.0000e-005	0.0000	0.3014	0.3014	9.0000e-005	0.0000	0.3038
Paving	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**1.7000e-004**	**1.4100e-003**	**9.8000e-004**	**0.0000**		**5.0000e-005**	**5.0000e-005**		**5.0000e-005**	**5.0000e-005**	**0.0000**	**0.3014**	**0.3014**	**9.0000e-005**	**0.0000**	**0.3038**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	1.0000e-004	3.0000e-005	0.0000	1.0000e-005	0.0000	1.0000e-005	0.0000	0.0000	0.0000	0.0000	0.0247	0.0247	0.0000	0.0000	0.0247
Worker	1.0000e-005	1.0000e-005	8.0000e-005	0.0000	2.0000e-005	0.0000	2.0000e-005	1.0000e-005	0.0000	1.0000e-005	0.0000	0.0198	0.0198	0.0000	0.0000	0.0198
Total	**1.0000e-005**	**1.1000e-004**	**1.1000e-004**	**0.0000**	**3.0000e-005**	**0.0000**	**3.0000e-005**	**1.0000e-005**	**0.0000**	**1.0000e-005**	**0.0000**	**0.0444**	**0.0444**	**0.0000**	**0.0000**	**0.0445**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	6.0000e-005	2.7000e-004	1.5600e-003	0.0000		1.0000e-005	1.0000e-005		1.0000e-005	1.0000e-005	0.0000	0.3014	0.3014	9.0000e-005	0.0000	0.3038
Paving	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**6.0000e-005**	**2.7000e-004**	**1.5600e-003**	**0.0000**		**1.0000e-005**	**1.0000e-005**		**1.0000e-005**	**1.0000e-005**	**0.0000**	**0.3014**	**0.3014**	**9.0000e-005**	**0.0000**	**0.3038**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	1.0000e-004	3.0000e-005	0.0000	1.0000e-005	0.0000	1.0000e-005	0.0000	0.0000	0.0000	0.0000	0.0247	0.0247	0.0000	0.0000	0.0247
Worker	1.0000e-005	1.0000e-005	8.0000e-005	0.0000	2.0000e-005	0.0000	2.0000e-005	1.0000e-005	0.0000	1.0000e-005	0.0000	0.0198	0.0198	0.0000	0.0000	0.0198
Total	**1.0000e-005**	**1.1000e-004**	**1.1000e-004**	**0.0000**	**3.0000e-005**	**0.0000**	**3.0000e-005**	**1.0000e-005**	**0.0000**	**1.0000e-005**	**0.0000**	**0.0444**	**0.0444**	**0.0000**	**0.0000**	**0.0445**

3.6 Install Fuel Gas Cleaning Vessel - 2021

Unmitigated Construction On-Site

Category	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	tons/yr										MT/yr					
Off-Road	0.0188	0.1739	0.1479	3.1000e-004		8.4600e-003	8.4600e-003		7.9600e-003	7.9600e-003	0.0000	27.0013	27.0013	7.3600e-003	0.0000	27.1854
Total	**0.0188**	**0.1739**	**0.1479**	**3.1000e-004**		**8.4600e-003**	**8.4600e-003**		**7.9600e-003**	**7.9600e-003**	**0.0000**	**27.0013**	**27.0013**	**7.3600e-003**	**0.0000**	**27.1854**

Unmitigated Construction Off-Site

Category	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	1.7000e-004	5.5300e-003	1.5000e-003	1.0000e-005	3.5000e-004	1.0000e-005	3.6000e-004	1.0000e-004	1.0000e-005	1.1000e-004	0.0000	1.3804	1.3804	8.0000e-005	0.0000	1.3825
Worker	3.0000e-004	2.3000e-004	2.6500e-003	1.0000e-005	7.7000e-004	1.0000e-005	7.7000e-004	2.0000e-004	1.0000e-005	2.1000e-004	0.0000	0.6922	0.6922	2.0000e-005	0.0000	0.6928
Total	**4.7000e-004**	**5.7600e-003**	**4.1500e-003**	**2.0000e-005**	**1.1200e-003**	**2.0000e-005**	**1.1300e-003**	**3.0000e-004**	**2.0000e-005**	**3.2000e-004**	**0.0000**	**2.0726**	**2.0726**	**1.0000e-004**	**0.0000**	**2.0753**

Mitigated Construction On-Site

Category	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	tons/yr										MT/yr					
Off-Road	6.6000e-003	0.0307	0.1795	3.1000e-004		1.2300e-003	1.2300e-003		1.2300e-003	1.2300e-003	0.0000	27.0012	27.0012	7.3600e-003	0.0000	27.1853

Total	**6.6000e-003**	**0.0307**	**0.1795**	**3.1000e-004**		**1.2300e-003**	**1.2300e-003**		**1.2300e-003**	**1.2300e-003**	**0.0000**	**27.0012**	**27.0012**	**7.3600e-003**	**0.0000**	**27.1853**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	1.7000e-004	5.5300e-003	1.5000e-003	1.0000e-005	3.5000e-004	1.0000e-005	3.6000e-004	1.0000e-004	1.0000e-005	1.1000e-004	0.0000	1.3804	1.3804	8.0000e-005	0.0000	1.3825
Worker	3.0000e-004	2.3000e-004	2.6500e-003	1.0000e-005	7.7000e-004	1.0000e-005	7.7000e-004	2.0000e-004	1.0000e-005	2.1000e-004	0.0000	0.6922	0.6922	2.0000e-005	0.0000	0.6928
Total	**4.7000e-004**	**5.7600e-003**	**4.1500e-003**	**2.0000e-005**	**1.1200e-003**	**2.0000e-005**	**1.1300e-003**	**3.0000e-004**	**2.0000e-005**	**3.2000e-004**	**0.0000**	**2.0726**	**2.0726**	**1.0000e-004**	**0.0000**	**2.0753**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Mitigated	6.0000e-005	3.1000e-004	8.7000e-004	0.0000	2.5000e-004	0.0000	2.5000e-004	7.0000e-005	0.0000	7.0000e-005	0.0000	0.2858	0.2858	1.0000e-005	0.0000	0.2862
Unmitigated	6.0000e-005	3.1000e-004	8.7000e-004	0.0000	2.5000e-004	0.0000	2.5000e-004	7.0000e-005	0.0000	7.0000e-005	0.0000	0.2858	0.2858	1.0000e-005	0.0000	0.2862

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
General Heavy Industry	0.15	0.15	0.15	664	664
Total	0.15	0.15	0.15	664	664

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
General Heavy Industry	16.60	8.40	6.90	59.00	28.00	13.00	92	5	3

4.4 Fleet Mix

Land Use	LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
General Heavy Industry	0.547192	0.045177	0.202743	0.121510	0.016147	0.006143	0.019743	0.029945	0.002479	0.002270	0.005078	0.000682	0.000891

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Electricity Mitigated						0.0000	0.0000		0.0000	0.0000	0.0000	0.6182	0.6182	1.0000e-005	0.0000	0.6195
Electricity Unmitigated						0.0000	0.0000		0.0000	0.0000	0.0000	0.6182	0.6182	1.0000e-005	0.0000	0.6195
NaturalGas Mitigated	1.0000e-005	9.0000e-005	7.0000e-005	0.0000		1.0000e-005	1.0000e-005		1.0000e-005	1.0000e-005	0.0000	0.0966	0.0966	0.0000	0.0000	0.0972
NaturalGas Unmitigated	1.0000e-005	9.0000e-005	7.0000e-005	0.0000		1.0000e-005	1.0000e-005		1.0000e-005	1.0000e-005	0.0000	0.0966	0.0966	0.0000	0.0000	0.0972

5.2 Energy by Land Use - NaturalGas

Unmitigated

Land Use	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	kBTU/yr	tons/yr										MT/yr					
General Heavy Industry	1810	1.0000e-005	9.0000e-005	7.0000e-005	0.0000		1.0000e-005	1.0000e-005		1.0000e-005	1.0000e-005	0.0000	0.0966	0.0966	0.0000	0.0000	0.0972
Total		**1.0000e-005**	**9.0000e-005**	**7.0000e-005**	**0.0000**		**1.0000e-005**	**1.0000e-005**		**1.0000e-005**	**1.0000e-005**	**0.0000**	**0.0966**	**0.0966**	**0.0000**	**0.0000**	**0.0972**

Mitigated

Land Use	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	kBTU/yr	tons/yr										MT/yr					
General Heavy Industry	1810	1.0000e-005	9.0000e-005	7.0000e-005	0.0000		1.0000e-005	1.0000e-005		1.0000e-005	1.0000e-005	0.0000	0.0966	0.0966	0.0000	0.0000	0.0972
Total		**1.0000e-005**	**9.0000e-005**	**7.0000e-005**	**0.0000**		**1.0000e-005**	**1.0000e-005**		**1.0000e-005**	**1.0000e-005**	**0.0000**	**0.0966**	**0.0966**	**0.0000**	**0.0000**	**0.0972**

5.3 Energy by Land Use - Electricity

Unmitigated

Land Use	Electricity Use	Total CO2	CH4	N2O	CO2e
	kWh/yr	MT/yr			
General Heavy Industry	1110	0.6182	1.0000e-005	0.0000	0.6195
Total		**0.6182**	**1.0000e-005**	**0.0000**	**0.6195**

Mitigated

Land Use	Electricity Use	Total CO2	CH4	N2O	CO2e
	kWh/yr	MT/yr			
General Heavy Industry	1110	0.6182	1.0000e-005	0.0000	0.6195
Total		**0.6182**	**1.0000e-005**	**0.0000**	**0.6195**

6.0 Area Detail

6.1 Mitigation Measures Area

Category	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	tons/yr										MT/yr					
Mitigated	4.1000e-004	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unmitigated	4.1000e-004	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

6.2 Area by SubCategory

Unmitigated

SubCategory	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	tons/yr										MT/yr					
Architectural Coating	5.0000e-005					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Consumer Products	3.6000e-004					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Landscaping	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**4.1000e-004**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	tons/yr										MT/yr					
Architectural Coating	5.0000e-005					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Consumer Products	3.6000e-004					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Landscaping	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**4.1000e-004**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

7.0 Water Detail

7.1 Mitigation Measures Water

	Total CO2	CH4	N2O	CO2e
Category	MT/yr			
Mitigated	0.1750	7.6000e-004	2.0000e-005	0.1995
Unmitigated	0.1750	7.6000e-004	2.0000e-005	0.1995

7.2 Water by Land Use

Unmitigated

	Indoor/Outdoor Use	Total CO2	CH4	N2O	CO2e
Land Use	Mgal	MT/yr			
General Heavy Industry	0.023125 / 0	0.1750	7.6000e-004	2.0000e-005	0.1995
Total		**0.1750**	**7.6000e-004**	**2.0000e-005**	**0.1995**

Mitigated

	Indoor/Outdoor Use	Total CO2	CH4	N2O	CO2e
Land Use	Mgal	MT/yr			
General Heavy Industry	0.023125 / 0	0.1750	7.6000e-004	2.0000e-005	0.1995
Total		**0.1750**	**7.6000e-004**	**2.0000e-005**	**0.1995**

8.0 Waste Detail

8.1 Mitigation Measures Waste

Category/Year

	Total CO2	CH4	N2O	CO2e
	MT/yr			

Mitigated	0.0244	1.4400e-003	0.0000	0.0604
Unmitigated	0.0244	1.4400e-003	0.0000	0.0604

8.2 Waste by Land Use

Unmitigated

	Waste Disposed	Total CO2	CH4	N2O	CO2e
Land Use	tons	MT/yr			
General Heavy Industry	0.12	0.0244	1.4400e-003	0.0000	0.0604
Total		**0.0244**	**1.4400e-003**	**0.0000**	**0.0604**

Mitigated

	Waste Disposed	Total CO2	CH4	N2O	CO2e
Land Use	tons	MT/yr			
General Heavy Industry	0.12	0.0244	1.4400e-003	0.0000	0.0604
Total		**0.0244**	**1.4400e-003**	**0.0000**	**0.0604**

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Stationary Equipment

Fire Pumps and Emergency Generators

Equipment Type	Number	Hours/Day	Hours/Year	Horse Power	Load Factor	Fuel Type

Boilers

Equipment Type	Number	Heat Input/Day	Heat Input/Year	Boiler Rating	Fuel Type

User Defined Equipment

Equipment Type	Number

11.0 Vegetation

Replace LNB with ULNB

Los Angeles-South Coast County, Summer

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
General Heavy Industry	0.10	1000sqft	0.00	100.00	0

1.2 Other Project Characteristics

Urbanization	Urban	**Wind Speed (m/s)**	2.2	**Precipitation Freq (Days)**	33
Climate Zone	11			**Operational Year**	2021
Utility Company	Los Angeles Department of Water & Power				
CO2 Intensity (lb/MWhr)	1227.89	**CH4 Intensity (lb/MWhr)**	0.029	**N2O Intensity (lb/MWhr)**	0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics -

Land Use - Per Rule Team estimate, foudation for fuel gas cleaning vessel might be 10 ft x 10 ft

Construction Phase - Conservatively assumed there is an existing coalescer vessel to be replaced by a new one. Per John Zink Company, installing 100 burners will take 3 months - a given heater affected by R1109.1 will likely have less burners.

Off-road Equipment - Equipment estimated by Rule team. A tractors/loaders/backhoes is used to represent skip loader.

Off-road Equipment - Off-highway trucks is representing concrete mixing/transportation truck. Coalescer vessel footprint is about 10 ft x 10 ft.

Off-road Equipment - Equipment estimated by rule team. A tractors/loaders/backhoes is used to represent skip loader.

Off-road Equipment - Equipment estimated by Rule team. One of the tractors/loaders/backhoes is used to represent skip loader.

Off-road Equipment - Estimated by rule team.

Trips and VMT - Trips estimated after consultation with Rule team.

Vehicle Emission Factors -

Vehicle Emission Factors -

Vehicle Emission Factors -

Construction Off-road Equipment Mitigation - Assume all equipment that is 50 hp or bigger will need to be Tier 4 Final.

Fleet Mix -

Table Name	Column Name	Default Value	New Value
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	3.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	3.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	4.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	2.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	4.00
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstructionPhase	NumDays	0.00	5.00
tblConstructionPhase	NumDays	0.00	1.00
tblConstructionPhase	NumDays	0.00	92.00
tblConstructionPhase	NumDays	0.00	1.00

tblConstructionPhase	NumDays	0.00	14.00
tblConstructionPhase	NumDaysWeek	5.00	7.00
tblConstructionPhase	NumDaysWeek	5.00	7.00
tblConstructionPhase	NumDaysWeek	5.00	7.00
tblConstructionPhase	NumDaysWeek	5.00	7.00
tblConstructionPhase	NumDaysWeek	5.00	7.00
tblOffRoadEquipment	OffRoadEquipmentType		Generator Sets
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	4.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	UsageHours	6.00	4.00
tblOffRoadEquipment	UsageHours	4.00	24.00
tblOffRoadEquipment	UsageHours	4.00	12.00
tblOffRoadEquipment	UsageHours	6.00	24.00
tblOffRoadEquipment	UsageHours	6.00	12.00
tblOffRoadEquipment	UsageHours	8.00	2.00
tblOffRoadEquipment	UsageHours	8.00	12.00
tblOffRoadEquipment	UsageHours	6.00	12.00
tblTripsAndVMT	HaulingTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripNumber	0.00	16.00
tblTripsAndVMT	VendorTripNumber	0.00	2.00

tblTripsAndVMT	VendorTripNumber	0.00	8.00
tblTripsAndVMT	WorkerTripNumber	13.00	10.00
tblTripsAndVMT	WorkerTripNumber	13.00	0.00
tblTripsAndVMT	WorkerTripNumber	3.00	8.00
tblTripsAndVMT	WorkerTripNumber	0.00	20.00
tblTripsAndVMT	WorkerTripNumber	5.00	4.00
tblTripsAndVMT	WorkerTripNumber	0.00	10.00

2.0 Emissions Summary

2.1 Overall Construction (Maximum Daily Emission)

<u>Unmitigated Construction</u>

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2021	6.5135	61.4195	51.2930	0.1086	0.6911	2.9654	3.6019	0.1818	2.8240	2.9655	0.0000	10,443.7431	10,443.7431	2.0913	0.0000	10,496.0261
Maximum	**6.5135**	**61.4195**	**51.2930**	**0.1086**	**0.6911**	**2.9654**	**3.6019**	**0.1818**	**2.8240**	**2.9655**	**0.0000**	**10,443.7431**	**10,443.7431**	**2.0913**	**0.0000**	**10,496.0261**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2021	1.7387	9.3757	58.8317	0.1086	0.6790	0.2631	0.8165	0.1800	0.2627	0.3958	0.0000	10,443.7431	10,443.7431	2.0913	0.0000	10,496.0261
Maximum	**1.7387**	**9.3757**	**58.8317**	**0.1086**	**0.6790**	**0.2631**	**0.8165**	**0.1800**	**0.2627**	**0.3958**	**0.0000**	**10,443.7431**	**10,443.7431**	**2.0913**	**0.0000**	**10,496.0261**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**

Percent Reduction	**73.31**	**84.74**	**-14.70**	**0.00**	**1.74**	**91.13**	**77.33**	**1.00**	**90.70**	**86.65**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	2.2300e-003	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-005	2.0000e-005	0.0000		2.0000e-005
Energy	5.0000e-005	4.9000e-004	4.1000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005		0.5834	0.5834	1.0000e-005	1.0000e-005	0.5869
Mobile	3.3000e-004	1.6200e-003	5.0100e-003	2.0000e-005	1.4100e-003	1.0000e-005	1.4300e-003	3.8000e-004	1.0000e-005	3.9000e-004		1.7937	1.7937	9.0000e-005		1.7960
Total	**2.6100e-003**	**2.1100e-003**	**5.4300e-003**	**2.0000e-005**	**1.4100e-003**	**5.0000e-005**	**1.4700e-003**	**3.8000e-004**	**5.0000e-005**	**4.3000e-004**		**2.3771**	**2.3771**	**1.0000e-004**	**1.0000e-005**	**2.3829**

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	2.2300e-003	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-005	2.0000e-005	0.0000		2.0000e-005
Energy	5.0000e-005	4.9000e-004	4.1000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005		0.5834	0.5834	1.0000e-005	1.0000e-005	0.5869
Mobile	3.3000e-004	1.6200e-003	5.0100e-003	2.0000e-005	1.4100e-003	1.0000e-005	1.4300e-003	3.8000e-004	1.0000e-005	3.9000e-004		1.7937	1.7937	9.0000e-005		1.7960
Total	**2.6100e-003**	**2.1100e-003**	**5.4300e-003**	**2.0000e-005**	**1.4100e-003**	**5.0000e-005**	**1.4700e-003**	**3.8000e-004**	**5.0000e-005**	**4.3000e-004**		**2.3771**	**2.3771**	**1.0000e-004**	**1.0000e-005**	**2.3829**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Demolition of existing Fuel Gas Cleaning Vessel	Demolition	6/7/2021	6/11/2021	7	5	
2	Scaffold Installation	Site Preparation	6/7/2021	6/7/2021	7	1	
3	Burner Replacement	Building Construction	6/7/2021	9/6/2021	7	92	
4	Concrete Pour -Fuel Gas Cleaning Vessel Foundation	Paving	6/12/2021	6/12/2021	7	1	
5	Install Fuel Gas Cleaning Vessel	Building Construction	6/13/2021	6/26/2021	7	14	

Acres of Grading (Site Preparation Phase): 0

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0; Striped Parking Area: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Demolition of existing Fuel Gas Cleaning Vessel	Air Compressors	1	12.00	78	0.48
Demolition of existing Fuel Gas Cleaning Vessel	Cranes	1	12.00	231	0.29

Demolition of existing Fuel Gas Cleaning Vessel	Forklifts	1	12.00	89	0.20
Demolition of existing Fuel Gas Cleaning Vessel	Tractors/Loaders/Backhoes	1	12.00	97	0.37
Scaffold Installation	Forklifts	1	12.00	89	0.20
Burner Replacement	Air Compressors	1	24.00	78	0.48
Burner Replacement	Cranes	1	24.00	231	0.29
Burner Replacement	Forklifts	1	24.00	89	0.20
Burner Replacement	Generator Sets	1	24.00	84	0.74
Burner Replacement	Tractors/Loaders/Backhoes	1	2.00	97	0.37
Concrete Pour -Fuel Gas Cleaning Vessel Foundation	Cement and Mortar Mixers	1	4.00	9	0.56
Concrete Pour -Fuel Gas Cleaning Vessel Foundation	Off-Highway Trucks	1	4.00	402	0.38
Install Fuel Gas Cleaning Vessel	Air Compressors	1	13.00	78	0.48
Install Fuel Gas Cleaning Vessel	Bore/Drill Rigs	1	12.00	221	0.50
Install Fuel Gas Cleaning Vessel	Cranes	1	12.00	231	0.29
Install Fuel Gas Cleaning Vessel	Forklifts	1	12.00	89	0.20
Install Fuel Gas Cleaning Vessel	Tractors/Loaders/Backhoes	2	12.00	97	0.37
Install Fuel Gas Cleaning Vessel	Welders	1	12.00	46	0.45
Demolition of existing Fuel Gas Cleaning Vessel	Generator Sets	1	12.00	84	0.74

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Demolition of existing Fuel Gas Cleaning	5	10.00	2.00	2.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Demolition of existing Fuel Gas Cleaning	5	0.00	0.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Scaffold Installation	1	8.00	2.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT

Burner Replacement	5	20.00	16.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Concrete Pour -Fuel Gas Cleaning Vessel	2	4.00	2.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Install Fuel Gas Cleaning Vessel	7	10.00	8.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Use Cleaner Engines for Construction Equipment

Water Exposed Area

3.2 Demolition of existing Fuel Gas Cleaning Vessel - 2021

<u>Unmitigated Construction On-Site</u>

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					0.0197	0.0000	0.0197	2.9800e-003	0.0000	2.9800e-003			0.0000			0.0000
Off-Road	2.0682	19.6893	17.2786	0.0314		1.0283	1.0283		0.9813	0.9813		3,008.9525	3,008.9525	0.5752		3,023.3317
Total	**2.0682**	**19.6893**	**17.2786**	**0.0314**	**0.0197**	**1.0283**	**1.0480**	**2.9800e-003**	**0.9813**	**0.9842**		**3,008.9525**	**3,008.9525**	**0.5752**		**3,023.3317**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	3.3400e-003	0.1073	0.0252	3.1000e-004	0.0123	3.3000e-004	0.0126	3.2200e-003	3.2000e-004	3.5300e-003		33.8579	33.8579	2.3000e-003		33.9153
Vendor	6.0800e-003	0.1942	0.0508	5.1000e-004	0.0219	4.0000e-004	0.0223	5.9300e-003	3.8000e-004	6.3100e-003		54.9761	54.9761	3.2400e-003		55.0571
Worker	0.0429	0.0295	0.4028	1.1400e-003	0.2090	9.0000e-004	0.2099	0.0535	8.3000e-004	0.0543		113.8770	113.8770	3.3600e-003		113.9609
Total	**0.0523**	**0.3309**	**0.4787**	**1.9600e-003**	**0.2432**	**1.6300e-003**	**0.2448**	**0.0627**	**1.5300e-003**	**0.0642**		**202.7110**	**202.7110**	**8.9000e-003**		**202.9333**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					7.6800e-003	0.0000	7.6800e-003	1.1600e-003	0.0000	1.1600e-003			0.0000			0.0000
Off-Road	0.3497	1.5152	18.9038	0.0314		0.0466	0.0466		0.0466	0.0466	0.0000	3,008.9525	3,008.9525	0.5752		3,023.3317
Total	**0.3497**	**1.5152**	**18.9038**	**0.0314**	**7.6800e-003**	**0.0466**	**0.0543**	**1.1600e-003**	**0.0466**	**0.0478**	**0.0000**	**3,008.9525**	**3,008.9525**	**0.5752**		**3,023.3317**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	3.3400e-003	0.1073	0.0252	3.1000e-004	0.0123	3.3000e-004	0.0126	3.2200e-003	3.2000e-004	3.5300e-003		33.8579	33.8579	2.3000e-003		33.9153
Vendor	6.0800e-003	0.1942	0.0508	5.1000e-004	0.0219	4.0000e-004	0.0223	5.9300e-003	3.8000e-004	6.3100e-003		54.9761	54.9761	3.2400e-003		55.0571
Worker	0.0429	0.0295	0.4028	1.1400e-003	0.2090	9.0000e-004	0.2099	0.0535	8.3000e-004	0.0543		113.8770	113.8770	3.3600e-003		113.9609
Total	**0.0523**	**0.3309**	**0.4787**	**1.9600e-003**	**0.2432**	**1.6300e-003**	**0.2448**	**0.0627**	**1.5300e-003**	**0.0642**		**202.7110**	**202.7110**	**8.9000e-003**		**202.9333**

3.3 Scaffold Installation - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.1940	1.7687	1.7518	2.2900e-003		0.1255	0.1255		0.1155	0.1155		222.0463	222.0463	0.0718		223.8416
Total	**0.1940**	**1.7687**	**1.7518**	**2.2900e-003**		**0.1255**	**0.1255**		**0.1155**	**0.1155**		**222.0463**	**222.0463**	**0.0718**		**223.8416**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	6.0800e-003	0.1942	0.0508	5.1000e-004	0.0128	4.0000e-004	0.0132	3.6900e-003	3.8000e-004	4.0700e-003		54.9761	54.9761	3.2400e-003		55.0571
Worker	0.0343	0.0236	0.3222	9.1000e-004	0.0894	7.2000e-004	0.0901	0.0237	6.7000e-004	0.0244		91.1016	91.1016	2.6800e-003		91.1687
Total	**0.0404**	**0.2178**	**0.3730**	**1.4200e-003**	**0.1022**	**1.1200e-003**	**0.1033**	**0.0274**	**1.0500e-003**	**0.0285**		**146.0777**	**146.0777**	**5.9200e-003**		**146.2258**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.0283	0.1224	1.7424	2.2900e-003		3.7700e-003	3.7700e-003		3.7700e-003	3.7700e-003	0.0000	222.0463	222.0463	0.0718		223.8416
Total	**0.0283**	**0.1224**	**1.7424**	**2.2900e-003**		**3.7700e-003**	**3.7700e-003**		**3.7700e-003**	**3.7700e-003**	**0.0000**	**222.0463**	**222.0463**	**0.0718**		**223.8416**

Mitigated Construction Off-Site

Category	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	6.0800e-003	0.1942	0.0508	5.1000e-004	0.0128	4.0000e-004	0.0132	3.6900e-003	3.8000e-004	4.0700e-003		54.9761	54.9761	3.2400e-003		55.0571
Worker	0.0343	0.0236	0.3222	9.1000e-004	0.0894	7.2000e-004	0.0901	0.0237	6.7000e-004	0.0244		91.1016	91.1016	2.6800e-003		91.1687
Total	**0.0404**	**0.2178**	**0.3730**	**1.4200e-003**	**0.1022**	**1.1200e-003**	**0.1033**	**0.0274**	**1.0500e-003**	**0.0285**		**146.0777**	**146.0777**	**5.9200e-003**		**146.2258**

3.4 Burner Replacement - 2021

Unmitigated Construction On-Site

Category	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	lb/day										lb/day					
Off-Road	3.6213	34.1652	28.3415	0.0543		1.7493	1.7493		1.6797	1.6797		5,190.4297	5,190.4297	0.8827		5,212.4977
Total	**3.6213**	**34.1652**	**28.3415**	**0.0543**		**1.7493**	**1.7493**		**1.6797**	**1.6797**		**5,190.4297**	**5,190.4297**	**0.8827**		**5,212.4977**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0486	1.5534	0.4061	4.1100e-003	0.1024	3.1800e-003	0.1056	0.0295	3.0400e-003	0.0325		439.8090	439.8090	0.0259		440.4568
Worker	0.0857	0.0589	0.8056	2.2900e-003	0.2236	1.8100e-003	0.2254	0.0593	1.6600e-003	0.0610		227.7540	227.7540	6.7100e-003		227.9217
Total	**0.1344**	**1.6124**	**1.2117**	**6.4000e-003**	**0.3260**	**4.9900e-003**	**0.3310**	**0.0888**	**4.7000e-003**	**0.0935**		**667.5630**	**667.5630**	**0.0326**		**668.3785**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.5949	2.5778	31.3669	0.0543		0.0793	0.0793		0.0793	0.0793	0.0000	5,190.4297	5,190.4297	0.8827		5,212.4977
Total	**0.5949**	**2.5778**	**31.3669**	**0.0543**		**0.0793**	**0.0793**		**0.0793**	**0.0793**	**0.0000**	**5,190.4297**	**5,190.4297**	**0.8827**		**5,212.4977**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0486	1.5534	0.4061	4.1100e-003	0.1024	3.1800e-003	0.1056	0.0295	3.0400e-003	0.0325		439.8090	439.8090	0.0259		440.4568
Worker	0.0857	0.0589	0.8056	2.2900e-003	0.2236	1.8100e-003	0.2254	0.0593	1.6600e-003	0.0610		227.7540	227.7540	6.7100e-003		227.9217
Total	**0.1344**	**1.6124**	**1.2117**	**6.4000e-003**	**0.3260**	**4.9900e-003**	**0.3310**	**0.0888**	**4.7000e-003**	**0.0935**		**667.5630**	**667.5630**	**0.0326**		**668.3785**

3.5 Concrete Pour -Fuel Gas Cleaning Vessel Foundation - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.3323	2.8158	1.9564	6.9600e-003		0.1037	0.1037		0.0960	0.0960		664.5197	664.5197	0.2094		669.7540
Paving	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Total	**0.3323**	**2.8158**	**1.9564**	**6.9600e-003**		**0.1037**	**0.1037**		**0.0960**	**0.0960**		**664.5197**	**664.5197**	**0.2094**		**669.7540**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	6.0800e-003	0.1942	0.0508	5.1000e-004	0.0128	4.0000e-004	0.0132	3.6900e-003	3.8000e-004	4.0700e-003		54.9761	54.9761	3.2400e-003		55.0571
Worker	0.0172	0.0118	0.1611	4.6000e-004	0.0447	3.6000e-004	0.0451	0.0119	3.3000e-004	0.0122		45.5508	45.5508	1.3400e-003		45.5844
Total	**0.0232**	**0.2060**	**0.2119**	**9.7000e-004**	**0.0575**	**7.6000e-004**	**0.0583**	**0.0156**	**7.1000e-004**	**0.0163**		**100.5269**	**100.5269**	**4.5800e-003**		**100.6415**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.1102	0.5343	3.1178	6.9600e-003		0.0179	0.0179		0.0179	0.0179	0.0000	664.5197	664.5197	0.2094		669.7540
Paving	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Total	**0.1102**	**0.5343**	**3.1178**	**6.9600e-003**		**0.0179**	**0.0179**		**0.0179**	**0.0179**	**0.0000**	**664.5197**	**664.5197**	**0.2094**		**669.7540**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	6.0800e-003	0.1942	0.0508	5.1000e-004	0.0128	4.0000e-004	0.0132	3.6900e-003	3.8000e-004	4.0700e-003		54.9761	54.9761	3.2400e-003		55.0571
Worker	0.0172	0.0118	0.1611	4.6000e-004	0.0447	3.6000e-004	0.0451	0.0119	3.3000e-004	0.0122		45.5508	45.5508	1.3400e-003		45.5844
Total	**0.0232**	**0.2060**	**0.2119**	**9.7000e-004**	**0.0575**	**7.6000e-004**	**0.0583**	**0.0156**	**7.1000e-004**	**0.0163**		**100.5269**	**100.5269**	**4.5800e-003**		**100.6415**

3.6 Install Fuel Gas Cleaning Vessel - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.6907	24.8358	21.1340	0.0447		1.2087	1.2087		1.1372	1.1372		4,251.9689	4,251.9689	1.1597		4,280.9607
Total	**2.6907**	**24.8358**	**21.1340**	**0.0447**		**1.2087**	**1.2087**		**1.1372**	**1.1372**		**4,251.9689**	**4,251.9689**	**1.1597**		**4,280.9607**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0243	0.7767	0.2031	2.0600e-003	0.0512	1.5900e-003	0.0528	0.0148	1.5200e-003	0.0163		219.9045	219.9045	0.0130		220.2284
Worker	0.0429	0.0295	0.4028	1.1400e-003	0.1118	9.0000e-004	0.1127	0.0296	8.3000e-004	0.0305		113.8770	113.8770	3.3600e-003		113.9609
Total	**0.0672**	**0.8062**	**0.6058**	**3.2000e-003**	**0.1630**	**2.4900e-003**	**0.1655**	**0.0444**	**2.3500e-003**	**0.0468**		**333.7815**	**333.7815**	**0.0163**		**334.1893**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.9423	4.3794	25.6473	0.0447		0.1763	0.1763		0.1763	0.1763	0.0000	4,251.9689	4,251.9689	1.1597		4,280.9606
Total	**0.9423**	**4.3794**	**25.6473**	**0.0447**		**0.1763**	**0.1763**		**0.1763**	**0.1763**	**0.0000**	**4,251.9689**	**4,251.9689**	**1.1597**		**4,280.9606**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0243	0.7767	0.2031	2.0600e-003	0.0512	1.5900e-003	0.0528	0.0148	1.5200e-003	0.0163		219.9045	219.9045	0.0130		220.2284
Worker	0.0429	0.0295	0.4028	1.1400e-003	0.1118	9.0000e-004	0.1127	0.0296	8.3000e-004	0.0305		113.8770	113.8770	3.3600e-003		113.9609
Total	**0.0672**	**0.8062**	**0.6058**	**3.2000e-003**	**0.1630**	**2.4900e-003**	**0.1655**	**0.0444**	**2.3500e-003**	**0.0468**		**333.7815**	**333.7815**	**0.0163**		**334.1893**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					

Mitigated	3.3000e-004	1.6200e-003	5.0100e-003	2.0000e-005	1.4100e-003	1.0000e-005	1.4300e-003	3.8000e-004	1.0000e-005	3.9000e-004		1.7937	1.7937	9.0000e-005		1.7960
Unmitigated	3.3000e-004	1.6200e-003	5.0100e-003	2.0000e-005	1.4100e-003	1.0000e-005	1.4300e-003	3.8000e-004	1.0000e-005	3.9000e-004		1.7937	1.7937	9.0000e-005		1.7960

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
General Heavy Industry	0.15	0.15	0.15	664	664
Total	0.15	0.15	0.15	664	664

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
General Heavy Industry	16.60	8.40	6.90	59.00	28.00	13.00	92	5	3

4.4 Fleet Mix

Land Use	LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
General Heavy Industry	0.547192	0.045177	0.202743	0.121510	0.016147	0.006143	0.019743	0.029945	0.002479	0.002270	0.005078	0.000682	0.000891

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
NaturalGas Mitigated	5.0000e-005	4.9000e-004	4.1000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005		0.5834	0.5834	1.0000e-005	1.0000e-005	0.5869
NaturalGas Unmitigated	5.0000e-005	4.9000e-004	4.1000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005		0.5834	0.5834	1.0000e-005	1.0000e-005	0.5869

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
General Heavy Industry	4.9589	5.0000e-005	4.9000e-004	4.1000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005		0.5834	0.5834	1.0000e-005	1.0000e-005	0.5869
Total		**5.0000e-005**	**4.9000e-004**	**4.1000e-004**	**0.0000**		**4.0000e-005**	**4.0000e-005**		**4.0000e-005**	**4.0000e-005**		**0.5834**	**0.5834**	**1.0000e-005**	**1.0000e-005**	**0.5869**

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
General Heavy Industry	0.0049589	5.0000e-005	4.9000e-004	4.1000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005		0.5834	0.5834	1.0000e-005	1.0000e-005	0.5869
Total		**5.0000e-005**	**4.9000e-004**	**4.1000e-004**	**0.0000**		**4.0000e-005**	**4.0000e-005**		**4.0000e-005**	**4.0000e-005**		**0.5834**	**0.5834**	**1.0000e-005**	**1.0000e-005**	**0.5869**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	2.2300e-003	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-005	2.0000e-005	0.0000		2.0000e-005
Unmitigated	2.2300e-003	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-005	2.0000e-005	0.0000		2.0000e-005

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	2.5000e-004					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	1.9800e-003					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	0.0000	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-005	2.0000e-005	0.0000		2.0000e-005
Total	**2.2300e-003**	**0.0000**	**1.0000e-005**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**2.0000e-005**	**2.0000e-005**	**0.0000**		**2.0000e-005**

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	2.5000e-004					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	1.9800e-003					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	0.0000	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-005	2.0000e-005	0.0000		2.0000e-005
Total	**2.2300e-003**	**0.0000**	**1.0000e-005**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**2.0000e-005**	**2.0000e-005**	**0.0000**		**2.0000e-005**

7.0 Water Detail

7.1 Mitigation Measures Water

8.0 Waste Detail

8.1 Mitigation Measures Waste

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Stationary Equipment

Fire Pumps and Emergency Generators

Equipment Type	Number	Hours/Day	Hours/Year	Horse Power	Load Factor	Fuel Type

Boilers

Equipment Type	Number	Heat Input/Day	Heat Input/Year	Boiler Rating	Fuel Type

User Defined Equipment

Equipment Type	Number

11.0 Vegetation

Replace LNB with ULNB

Los Angeles-South Coast County, Winter

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
General Heavy Industry	0.10	1000sqft	0.00	100.00	0

1.2 Other Project Characteristics

Urbanization Urban **Wind Speed (m/s)** 2.2 **Precipitation Freq (Days)** 33

Climate Zone 11 **Operational Year** 2021

Utility Company Los Angeles Department of Water & Power

CO2 Intensity (lb/MWhr) 1227.89 **CH4 Intensity (lb/MWhr)** 0.029 **N2O Intensity (lb/MWhr)** 0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics -

Land Use - Per Rule Team estimate, foudation for fuel gas cleaning vessel might be 10 ft x 10 ft

Construction Phase - Conservatively assumed there is an existing coalescer vessel to be replaced by a new one. Per John Zink Company, installing 100 burners will take 3 months - a given heater affected by R1109.1 will likely have less burners.

Off-road Equipment - Equipment estimated by Rule team. A tractors/loaders/backhoes is used to represent skip loader.

Off-road Equipment - Off-highway trucks is representing concrete mixing/transportation truck. Coalescer vessel footprint is about 10 ft x 10 ft.

Off-road Equipment - Equipment estimated by rule team. A tractors/loaders/backhoes is used to represent skip loader.

Off-road Equipment - Equipment estimated by Rule team. One of the tractors/loaders/backhoes is used to represent skip loader.

Off-road Equipment - Estimated by rule team.

Trips and VMT - Trips estimated after consultation with Rule team.

Vehicle Emission Factors -

Vehicle Emission Factors -

Vehicle Emission Factors -

Construction Off-road Equipment Mitigation - Assume all equipment that is 50 hp or bigger will need to be Tier 4 Final.

Fleet Mix -

Table Name	Column Name	Default Value	New Value
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	3.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	3.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	4.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	2.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	4.00
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstructionPhase	NumDays	0.00	5.00
tblConstructionPhase	NumDays	0.00	1.00
tblConstructionPhase	NumDays	0.00	92.00
tblConstructionPhase	NumDays	0.00	1.00

tblConstructionPhase	NumDays	0.00	14.00
tblConstructionPhase	NumDaysWeek	5.00	7.00
tblConstructionPhase	NumDaysWeek	5.00	7.00
tblConstructionPhase	NumDaysWeek	5.00	7.00
tblConstructionPhase	NumDaysWeek	5.00	7.00
tblConstructionPhase	NumDaysWeek	5.00	7.00
tblOffRoadEquipment	OffRoadEquipmentType		Generator Sets
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	4.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	UsageHours	6.00	4.00
tblOffRoadEquipment	UsageHours	4.00	24.00
tblOffRoadEquipment	UsageHours	4.00	12.00
tblOffRoadEquipment	UsageHours	6.00	24.00
tblOffRoadEquipment	UsageHours	6.00	12.00
tblOffRoadEquipment	UsageHours	8.00	2.00
tblOffRoadEquipment	UsageHours	8.00	12.00
tblOffRoadEquipment	UsageHours	6.00	12.00
tblTripsAndVMT	HaulingTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripNumber	0.00	16.00
tblTripsAndVMT	VendorTripNumber	0.00	2.00

tblTripsAndVMT	VendorTripNumber	0.00	8.00
tblTripsAndVMT	WorkerTripNumber	13.00	10.00
tblTripsAndVMT	WorkerTripNumber	13.00	0.00
tblTripsAndVMT	WorkerTripNumber	3.00	8.00
tblTripsAndVMT	WorkerTripNumber	0.00	20.00
tblTripsAndVMT	WorkerTripNumber	5.00	4.00
tblTripsAndVMT	WorkerTripNumber	0.00	10.00

2.0 Emissions Summary

2.1 Overall Construction (Maximum Daily Emission)

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2021	6.5316	61.4242	51.2541	0.1082	0.6911	2.9656	3.6021	0.1818	2.8241	2.9657	0.0000	10,405.7032	10,405.7032	2.0933	0.0000	10,458.0351
Maximum	**6.5316**	**61.4242**	**51.2541**	**0.1082**	**0.6911**	**2.9656**	**3.6021**	**0.1818**	**2.8241**	**2.9657**	**0.0000**	**10,405.7032**	**10,405.7032**	**2.0933**	**0.0000**	**10,458.0351**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2021	1.7568	9.3803	58.7928	0.1082	0.6790	0.2632	0.8166	0.1800	0.2628	0.3960	0.0000	10,405.7032	10,405.7032	2.0933	0.0000	10,458.0351
Maximum	**1.7568**	**9.3803**	**58.7928**	**0.1082**	**0.6790**	**0.2632**	**0.8166**	**0.1800**	**0.2628**	**0.3960**	**0.0000**	**10,405.7032**	**10,405.7032**	**2.0933**	**0.0000**	**10,458.0351**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**

Percent Reduction	**73.10**	**84.73**	**-14.71**	**0.00**	**1.74**	**91.12**	**77.33**	**1.00**	**90.69**	**86.65**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

2.2 Overall Operational

<u>Unmitigated Operational</u>

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	2.2300e-003	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-005	2.0000e-005	0.0000		2.0000e-005
Energy	5.0000e-005	4.9000e-004	4.1000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005		0.5834	0.5834	1.0000e-005	1.0000e-005	0.5869
Mobile	3.2000e-004	1.6700e-003	4.7100e-003	2.0000e-005	1.4100e-003	1.0000e-005	1.4300e-003	3.8000e-004	1.0000e-005	3.9000e-004		1.7079	1.7079	9.0000e-005		1.7101
Total	**2.6000e-003**	**2.1600e-003**	**5.1300e-003**	**2.0000e-005**	**1.4100e-003**	**5.0000e-005**	**1.4700e-003**	**3.8000e-004**	**5.0000e-005**	**4.3000e-004**		**2.2913**	**2.2913**	**1.0000e-004**	**1.0000e-005**	**2.2970**

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	2.2300e-003	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-005	2.0000e-005	0.0000		2.0000e-005
Energy	5.0000e-005	4.9000e-004	4.1000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005		0.5834	0.5834	1.0000e-005	1.0000e-005	0.5869
Mobile	3.2000e-004	1.6700e-003	4.7100e-003	2.0000e-005	1.4100e-003	1.0000e-005	1.4300e-003	3.8000e-004	1.0000e-005	3.9000e-004		1.7079	1.7079	9.0000e-005		1.7101
Total	**2.6000e-003**	**2.1600e-003**	**5.1300e-003**	**2.0000e-005**	**1.4100e-003**	**5.0000e-005**	**1.4700e-003**	**3.8000e-004**	**5.0000e-005**	**4.3000e-004**		**2.2913**	**2.2913**	**1.0000e-004**	**1.0000e-005**	**2.2970**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Demolition of existing Fuel Gas Cleaning Vessel	Demolition	6/7/2021	6/11/2021	7	5	
2	Scaffold Installation	Site Preparation	6/7/2021	6/7/2021	7	1	
3	Burner Replacement	Building Construction	6/7/2021	9/6/2021	7	92	
4	Concrete Pour -Fuel Gas Cleaning Vessel Foundation	Paving	6/12/2021	6/12/2021	7	1	
5	Install Fuel Gas Cleaning Vessel	Building Construction	6/13/2021	6/26/2021	7	14	

Acres of Grading (Site Preparation Phase): 0

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0; Striped Parking Area: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Demolition of existing Fuel Gas Cleaning Vessel	Air Compressors	1	12.00	78	0.48
Demolition of existing Fuel Gas Cleaning Vessel	Cranes	1	12.00	231	0.29

Demolition of existing Fuel Gas Cleaning Vessel	Forklifts	1	12.00	89	0.20
Demolition of existing Fuel Gas Cleaning Vessel	Tractors/Loaders/Backhoes	1	12.00	97	0.37
Scaffold Installation	Forklifts	1	12.00	89	0.20
Burner Replacement	Air Compressors	1	24.00	78	0.48
Burner Replacement	Cranes	1	24.00	231	0.29
Burner Replacement	Forklifts	1	24.00	89	0.20
Burner Replacement	Generator Sets	1	24.00	84	0.74
Burner Replacement	Tractors/Loaders/Backhoes	1	2.00	97	0.37
Concrete Pour -Fuel Gas Cleaning Vessel Foundation	Cement and Mortar Mixers	1	4.00	9	0.56
Concrete Pour -Fuel Gas Cleaning Vessel Foundation	Off-Highway Trucks	1	4.00	402	0.38
Install Fuel Gas Cleaning Vessel	Air Compressors	1	13.00	78	0.48
Install Fuel Gas Cleaning Vessel	Bore/Drill Rigs	1	12.00	221	0.50
Install Fuel Gas Cleaning Vessel	Cranes	1	12.00	231	0.29
Install Fuel Gas Cleaning Vessel	Forklifts	1	12.00	89	0.20
Install Fuel Gas Cleaning Vessel	Tractors/Loaders/Backhoes	2	12.00	97	0.37
Install Fuel Gas Cleaning Vessel	Welders	1	12.00	46	0.45
Demolition of existing Fuel Gas Cleaning Vessel	Generator Sets	1	12.00	84	0.74

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Demolition of existing Fuel Gas Cleaning	5	10.00	2.00	2.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Demolition of existing Fuel Gas Cleaning	5	0.00	0.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Scaffold Installation	1	8.00	2.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT

Burner Replacement	5	20.00	16.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Concrete Pour -Fuel Gas Cleaning Vessel	2	4.00	2.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Install Fuel Gas Cleaning Vessel	7	10.00	8.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Use Cleaner Engines for Construction Equipment

Water Exposed Area

3.2 Demolition of existing Fuel Gas Cleaning Vessel - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					0.0197	0.0000	0.0197	2.9800e-003	0.0000	2.9800e-003			0.0000			0.0000
Off-Road	2.0682	19.6893	17.2786	0.0314		1.0283	1.0283		0.9813	0.9813		3,008.9525	3,008.9525	0.5752		3,023.3317
Total	**2.0682**	**19.6893**	**17.2786**	**0.0314**	**0.0197**	**1.0283**	**1.0480**	**2.9800e-003**	**0.9813**	**0.9842**		**3,008.9525**	**3,008.9525**	**0.5752**		**3,023.3317**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	3.4200e-003	0.1086	0.0267	3.1000e-004	0.0123	3.3000e-004	0.0126	3.2200e-003	3.2000e-004	3.5400e-003		33.2713	33.2713	2.3800e-003		33.3308
Vendor	6.3800e-003	0.1938	0.0562	5.0000e-004	0.0219	4.1000e-004	0.0223	5.9300e-003	3.9000e-004	6.3200e-003		53.4691	53.4691	3.4500e-003		53.5554
Worker	0.0477	0.0326	0.3683	1.0800e-003	0.2090	9.0000e-004	0.2099	0.0535	8.3000e-004	0.0543		107.2251	107.2251	3.1600e-003		107.3040
Total	**0.0575**	**0.3350**	**0.4511**	**1.8900e-003**	**0.2432**	**1.6400e-003**	**0.2448**	**0.0627**	**1.5400e-003**	**0.0642**		**193.9655**	**193.9655**	**8.9900e-003**		**194.1902**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					7.6800e-003	0.0000	7.6800e-003	1.1600e-003	0.0000	1.1600e-003			0.0000			0.0000
Off-Road	0.3497	1.5152	18.9038	0.0314		0.0466	0.0466		0.0466	0.0466	0.0000	3,008.9525	3,008.9525	0.5752		3,023.3317
Total	**0.3497**	**1.5152**	**18.9038**	**0.0314**	**7.6800e-003**	**0.0466**	**0.0543**	**1.1600e-003**	**0.0466**	**0.0478**	**0.0000**	**3,008.9525**	**3,008.9525**	**0.5752**		**3,023.3317**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	3.4200e-003	0.1086	0.0267	3.1000e-004	0.0123	3.3000e-004	0.0126	3.2200e-003	3.2000e-004	3.5400e-003		33.2713	33.2713	2.3800e-003		33.3308
Vendor	6.3800e-003	0.1938	0.0562	5.0000e-004	0.0219	4.1000e-004	0.0223	5.9300e-003	3.9000e-004	6.3200e-003		53.4691	53.4691	3.4500e-003		53.5554
Worker	0.0477	0.0326	0.3683	1.0800e-003	0.2090	9.0000e-004	0.2099	0.0535	8.3000e-004	0.0543		107.2251	107.2251	3.1600e-003		107.3040
Total	**0.0575**	**0.3350**	**0.4511**	**1.8900e-003**	**0.2432**	**1.6400e-003**	**0.2448**	**0.0627**	**1.5400e-003**	**0.0642**		**193.9655**	**193.9655**	**8.9900e-003**		**194.1902**

3.3 Scaffold Installation - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.1940	1.7687	1.7518	2.2900e-003		0.1255	0.1255		0.1155	0.1155		222.0463	222.0463	0.0718		223.8416
Total	**0.1940**	**1.7687**	**1.7518**	**2.2900e-003**		**0.1255**	**0.1255**		**0.1155**	**0.1155**		**222.0463**	**222.0463**	**0.0718**		**223.8416**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	6.3800e-003	0.1938	0.0562	5.0000e-004	0.0128	4.1000e-004	0.0132	3.6900e-003	3.9000e-004	4.0800e-003		53.4691	53.4691	3.4500e-003		53.5554
Worker	0.0382	0.0261	0.2946	8.6000e-004	0.0894	7.2000e-004	0.0901	0.0237	6.7000e-004	0.0244		85.7801	85.7801	2.5200e-003		85.8432
Total	**0.0445**	**0.2199**	**0.3508**	**1.3600e-003**	**0.1022**	**1.1300e-003**	**0.1034**	**0.0274**	**1.0600e-003**	**0.0285**		**139.2492**	**139.2492**	**5.9700e-003**		**139.3986**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.0283	0.1224	1.7424	2.2900e-003		3.7700e-003	3.7700e-003		3.7700e-003	3.7700e-003	0.0000	222.0463	222.0463	0.0718		223.8416
Total	**0.0283**	**0.1224**	**1.7424**	**2.2900e-003**		**3.7700e-003**	**3.7700e-003**		**3.7700e-003**	**3.7700e-003**	**0.0000**	**222.0463**	**222.0463**	**0.0718**		**223.8416**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	6.3800e-003	0.1938	0.0562	5.0000e-004	0.0128	4.1000e-004	0.0132	3.6900e-003	3.9000e-004	4.0800e-003		53.4691	53.4691	3.4500e-003		53.5554
Worker	0.0382	0.0261	0.2946	8.6000e-004	0.0894	7.2000e-004	0.0901	0.0237	6.7000e-004	0.0244		85.7801	85.7801	2.5200e-003		85.8432
Total	**0.0445**	**0.2199**	**0.3508**	**1.3600e-003**	**0.1022**	**1.1300e-003**	**0.1034**	**0.0274**	**1.0600e-003**	**0.0285**		**139.2492**	**139.2492**	**5.9700e-003**		**139.3986**

3.4 Burner Replacement - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	3.6213	34.1652	28.3415	0.0543		1.7493	1.7493		1.6797	1.6797		5,190.4297	5,190.4297	0.8827		5,212.4977
Total	**3.6213**	**34.1652**	**28.3415**	**0.0543**		**1.7493**	**1.7493**		**1.6797**	**1.6797**		**5,190.4297**	**5,190.4297**	**0.8827**		**5,212.4977**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0511	1.5502	0.4492	4.0000e-003	0.1024	3.2800e-003	0.1057	0.0295	3.1400e-003	0.0326		427.7528	427.7528	0.0276		428.4432
Worker	0.0954	0.0652	0.7365	2.1500e-003	0.2236	1.8100e-003	0.2254	0.0593	1.6600e-003	0.0610		214.4502	214.4502	6.3100e-003		214.6080
Total	**0.1464**	**1.6155**	**1.1857**	**6.1500e-003**	**0.3260**	**5.0900e-003**	**0.3311**	**0.0888**	**4.8000e-003**	**0.0936**		**642.2031**	**642.2031**	**0.0339**		**643.0512**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.5949	2.5778	31.3669	0.0543		0.0793	0.0793		0.0793	0.0793	0.0000	5,190.4297	5,190.4297	0.8827		5,212.4977
Total	**0.5949**	**2.5778**	**31.3669**	**0.0543**		**0.0793**	**0.0793**		**0.0793**	**0.0793**	**0.0000**	**5,190.4297**	**5,190.4297**	**0.8827**		**5,212.4977**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0511	1.5502	0.4492	4.0000e-003	0.1024	3.2800e-003	0.1057	0.0295	3.1400e-003	0.0326		427.7528	427.7528	0.0276		428.4432
Worker	0.0954	0.0652	0.7365	2.1500e-003	0.2236	1.8100e-003	0.2254	0.0593	1.6600e-003	0.0610		214.4502	214.4502	6.3100e-003		214.6080
Total	**0.1464**	**1.6155**	**1.1857**	**6.1500e-003**	**0.3260**	**5.0900e-003**	**0.3311**	**0.0888**	**4.8000e-003**	**0.0936**		**642.2031**	**642.2031**	**0.0339**		**643.0512**

3.5 Concrete Pour -Fuel Gas Cleaning Vessel Foundation - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.3323	2.8158	1.9564	6.9600e-003		0.1037	0.1037		0.0960	0.0960		664.5197	664.5197	0.2094		669.7540
Paving	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Total	**0.3323**	**2.8158**	**1.9564**	**6.9600e-003**		**0.1037**	**0.1037**		**0.0960**	**0.0960**		**664.5197**	**664.5197**	**0.2094**		**669.7540**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	6.3800e-003	0.1938	0.0562	5.0000e-004	0.0128	4.1000e-004	0.0132	3.6900e-003	3.9000e-004	4.0800e-003		53.4691	53.4691	3.4500e-003		53.5554
Worker	0.0191	0.0131	0.1473	4.3000e-004	0.0447	3.6000e-004	0.0451	0.0119	3.3000e-004	0.0122		42.8900	42.8900	1.2600e-003		42.9216
Total	**0.0255**	**0.2068**	**0.2035**	**9.3000e-004**	**0.0575**	**7.7000e-004**	**0.0583**	**0.0156**	**7.2000e-004**	**0.0163**		**96.3592**	**96.3592**	**4.7100e-003**		**96.4770**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.1102	0.5343	3.1178	6.9600e-003		0.0179	0.0179		0.0179	0.0179	0.0000	664.5197	664.5197	0.2094		669.7540
Paving	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Total	**0.1102**	**0.5343**	**3.1178**	**6.9600e-003**		**0.0179**	**0.0179**		**0.0179**	**0.0179**	**0.0000**	**664.5197**	**664.5197**	**0.2094**		**669.7540**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	6.3800e-003	0.1938	0.0562	5.0000e-004	0.0128	4.1000e-004	0.0132	3.6900e-003	3.9000e-004	4.0800e-003		53.4691	53.4691	3.4500e-003		53.5554
Worker	0.0191	0.0131	0.1473	4.3000e-004	0.0447	3.6000e-004	0.0451	0.0119	3.3000e-004	0.0122		42.8900	42.8900	1.2600e-003		42.9216
Total	**0.0255**	**0.2068**	**0.2035**	**9.3000e-004**	**0.0575**	**7.7000e-004**	**0.0583**	**0.0156**	**7.2000e-004**	**0.0163**		**96.3592**	**96.3592**	**4.7100e-003**		**96.4770**

3.6 Install Fuel Gas Cleaning Vessel - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.6907	24.8358	21.1340	0.0447		1.2087	1.2087		1.1372	1.1372		4,251.9689	4,251.9689	1.1597		4,280.9607
Total	**2.6907**	**24.8358**	**21.1340**	**0.0447**		**1.2087**	**1.2087**		**1.1372**	**1.1372**		**4,251.9689**	**4,251.9689**	**1.1597**		**4,280.9607**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0255	0.7751	0.2246	2.0000e-003	0.0512	1.6400e-003	0.0529	0.0148	1.5700e-003	0.0163		213.8764	213.8764	0.0138		214.2216
Worker	0.0477	0.0326	0.3683	1.0800e-003	0.1118	9.0000e-004	0.1127	0.0296	8.3000e-004	0.0305		107.2251	107.2251	3.1600e-003		107.3040
Total	**0.0732**	**0.8077**	**0.5929**	**3.0800e-003**	**0.1630**	**2.5400e-003**	**0.1655**	**0.0444**	**2.4000e-003**	**0.0468**		**321.1015**	**321.1015**	**0.0170**		**321.5256**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.9423	4.3794	25.6473	0.0447		0.1763	0.1763		0.1763	0.1763	0.0000	4,251.9689	4,251.9689	1.1597		4,280.9606
Total	**0.9423**	**4.3794**	**25.6473**	**0.0447**		**0.1763**	**0.1763**		**0.1763**	**0.1763**	**0.0000**	**4,251.9689**	**4,251.9689**	**1.1597**		**4,280.9606**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0255	0.7751	0.2246	2.0000e-003	0.0512	1.6400e-003	0.0529	0.0148	1.5700e-003	0.0163		213.8764	213.8764	0.0138		214.2216
Worker	0.0477	0.0326	0.3683	1.0800e-003	0.1118	9.0000e-004	0.1127	0.0296	8.3000e-004	0.0305		107.2251	107.2251	3.1600e-003		107.3040
Total	**0.0732**	**0.8077**	**0.5929**	**3.0800e-003**	**0.1630**	**2.5400e-003**	**0.1655**	**0.0444**	**2.4000e-003**	**0.0468**		**321.1015**	**321.1015**	**0.0170**		**321.5256**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					

Mitigated	3.2000e-004	1.6700e-003	4.7100e-003	2.0000e-005	1.4100e-003	1.0000e-005	1.4300e-003	3.8000e-004	1.0000e-005	3.9000e-004		1.7079	1.7079	9.0000e-005		1.7101
Unmitigated	3.2000e-004	1.6700e-003	4.7100e-003	2.0000e-005	1.4100e-003	1.0000e-005	1.4300e-003	3.8000e-004	1.0000e-005	3.9000e-004		1.7079	1.7079	9.0000e-005		1.7101

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
General Heavy Industry	0.15	0.15	0.15	664	664
Total	0.15	0.15	0.15	664	664

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
General Heavy Industry	16.60	8.40	6.90	59.00	28.00	13.00	92	5	3

4.4 Fleet Mix

Land Use	LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
General Heavy Industry	0.547192	0.045177	0.202743	0.121510	0.016147	0.006143	0.019743	0.029945	0.002479	0.002270	0.005078	0.000682	0.000891

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
NaturalGas Mitigated	5.0000e-005	4.9000e-004	4.1000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005		0.5834	0.5834	1.0000e-005	1.0000e-005	0.5869
NaturalGas Unmitigated	5.0000e-005	4.9000e-004	4.1000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005		0.5834	0.5834	1.0000e-005	1.0000e-005	0.5869

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
General Heavy Industry	4.9589	5.0000e-005	4.9000e-004	4.1000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005		0.5834	0.5834	1.0000e-005	1.0000e-005	0.5869
Total		**5.0000e-005**	**4.9000e-004**	**4.1000e-004**	**0.0000**		**4.0000e-005**	**4.0000e-005**		**4.0000e-005**	**4.0000e-005**		**0.5834**	**0.5834**	**1.0000e-005**	**1.0000e-005**	**0.5869**

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
General Heavy Industry	0.0049589	5.0000e-005	4.9000e-004	4.1000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005		0.5834	0.5834	1.0000e-005	1.0000e-005	0.5869
Total		**5.0000e-005**	**4.9000e-004**	**4.1000e-004**	**0.0000**		**4.0000e-005**	**4.0000e-005**		**4.0000e-005**	**4.0000e-005**		**0.5834**	**0.5834**	**1.0000e-005**	**1.0000e-005**	**0.5869**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	2.2300e-003	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-005	2.0000e-005	0.0000		2.0000e-005
Unmitigated	2.2300e-003	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-005	2.0000e-005	0.0000		2.0000e-005

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	2.5000e-004					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	1.9800e-003					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	0.0000	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-005	2.0000e-005	0.0000		2.0000e-005
Total	**2.2300e-003**	**0.0000**	**1.0000e-005**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**2.0000e-005**	**2.0000e-005**	**0.0000**		**2.0000e-005**

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	2.5000e-004					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	1.9800e-003					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	0.0000	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-005	2.0000e-005	0.0000		2.0000e-005
Total	**2.2300e-003**	**0.0000**	**1.0000e-005**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**2.0000e-005**	**2.0000e-005**	**0.0000**		**2.0000e-005**

7.0 Water Detail

7.1 Mitigation Measures Water

8.0 Waste Detail

8.1 Mitigation Measures Waste

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Stationary Equipment

Fire Pumps and Emergency Generators

Equipment Type	Number	Hours/Day	Hours/Year	Horse Power	Load Factor	Fuel Type

Boilers

Equipment Type	Number	Heat Input/Day	Heat Input/Year	Boiler Rating	Fuel Type

User Defined Equipment

Equipment Type	Number

11.0 Vegetation

Replace LNB with ULNB

Los Angeles-South Coast County, Mitigation Report

Construction Mitigation Summary

Phase	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Percent Reduction												
Burner Replacement	0.81	0.88	-0.10	0.00	0.95	0.95	0.00	0.00	0.00	0.00	0.00	0.00
Concrete Pour -Fuel Gas Cleaning Vessel Foundation	0.61	0.75	-0.53	0.00	0.80	0.80	0.00	0.00	0.00	0.00	0.00	0.00
Demolition of existing Fuel Gas Cleaning Vessel	0.81	0.91	-0.09	0.00	0.95	0.95	0.00	0.00	0.00	0.00	0.00	0.00
Install Fuel Gas Cleaning Vessel	0.63	0.80	-0.21	0.00	0.85	0.84	0.00	0.00	0.00	0.00	0.00	0.00
Scaffold Installation	0.75	0.83	0.01	0.00	1.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00

OFFROAD Equipment Mitigation

Equipment Type	Fuel Type	Tier	Number Mitigated	Total Number of Equipment	DPF	Oxidation Catalyst
Air Compressors	Diesel	Tier 4 Final	3	3	No Change	0.00
Bore/Drill Rigs	Diesel	Tier 4 Final	1	1	No Change	0.00
Cement and Mortar Mixers	Diesel	No Change	0	1	No Change	0.00
Cranes	Diesel	Tier 4 Final	3	3	No Change	0.00
Forklifts	Diesel	Tier 4 Final	4	4	No Change	0.00
Generator Sets	Diesel	Tier 4 Final	2	2	No Change	0.00
Off-Highway Trucks	Diesel	Tier 4 Final	1	1	No Change	0.00
Tractors/Loaders/Backhoes	Diesel	Tier 4 Final	4	4	No Change	0.00
Welders	Diesel	No Change	0	1	No Change	0.00

Equipment Type	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	Unmitigated tons/yr						Unmitigated mt/yr					
Air Compressors	4.46900E-002	3.11730E-001	3.71080E-001	6.10000E-004	1.92100E-002	1.92100E-002	0.00000E+000	5.21289E+001	5.21289E+001	3.58000E-003	0.00000E+000	5.22184E+001
Bore/Drill Rigs	2.71000E-003	3.17400E-002	2.17800E-002	1.00000E-004	9.60000E-004	8.90000E-004	0.00000E+000	8.68780E+000	8.68780E+000	2.81000E-003	0.00000E+000	8.75804E+000
Cement and Mortar Mixers	1.00000E-005	9.00000E-005	8.00000E-005	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	1.14600E-002	1.14600E-002	0.00000E+000	0.00000E+000	1.14900E-002
Cranes	6.28600E-002	7.38310E-001	3.01890E-001	8.80000E-004	2.99800E-002	2.75800E-002	0.00000E+000	7.71724E+001	7.71724E+001	2.49600E-002	0.00000E+000	7.77964E+001
Forklifts	1.97900E-002	1.80410E-001	1.78680E-001	2.30000E-004	1.28100E-002	1.17800E-002	0.00000E+000	2.05466E+001	2.05466E+001	6.65000E-003	0.00000E+000	2.07127E+001
Generator Sets	5.06600E-002	4.48800E-001	5.22310E-001	9.30000E-004	2.37800E-002	2.37800E-002	0.00000E+000	8.01182E+001	8.01182E+001	4.09000E-003	0.00000E+000	8.02204E+001
Off-Highway Trucks	1.50000E-004	1.32000E-003	9.00000E-004	0.00000E+000	5.00000E-005	4.00000E-005	0.00000E+000	2.89960E-001	2.89960E-001	9.00000E-005	0.00000E+000	2.92310E-001
Tractors/Loaders/Backhoes	6.79000E-003	6.87200E-002	8.19300E-002	1.10000E-004	4.05000E-003	3.73000E-003	0.00000E+000	9.89523E+000	9.89523E+000	3.20000E-003	0.00000E+000	9.97524E+000
Welders	3.18000E-003	1.58400E-002	1.80500E-002	3.00000E-005	7.80000E-004	7.80000E-004	0.00000E+000	1.97632E+000	1.97632E+000	2.60000E-004	0.00000E+000	1.98275E+000

Equipment Type	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	Mitigated tons/yr						Mitigated mt/yr					
Air Compressors	6.07000E-003	2.62900E-002	3.74120E-001	6.10000E-004	8.10000E-004	8.10000E-004	0.00000E+000	5.21289E+001	5.21289E+001	3.58000E-003	0.00000E+000	5.22183E+001
Bore/Drill Rigs	1.23000E-003	5.32000E-003	4.50200E-002	1.00000E-004	1.60000E-004	1.60000E-004	0.00000E+000	8.68779E+000	8.68779E+000	2.81000E-003	0.00000E+000	8.75803E+000
Cement and Mortar Mixers	1.00000E-005	9.00000E-005	8.00000E-005	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	1.14600E-002	1.14600E-002	0.00000E+000	0.00000E+000	1.14900E-002
Cranes	1.07900E-002	4.67700E-002	3.95740E-001	8.80000E-004	1.44000E-003	1.44000E-003	0.00000E+000	7.71723E+001	7.71723E+001	2.49600E-002	0.00000E+000	7.77963E+001
Forklifts	2.88000E-003	1.24900E-002	1.77720E-001	2.30000E-004	3.80000E-004	3.80000E-004	0.00000E+000	2.05466E+001	2.05466E+001	6.65000E-003	0.00000E+000	2.07127E+001
Generator Sets	9.32000E-003	4.04000E-002	5.74990E-001	9.30000E-004	1.24000E-003	1.24000E-003	0.00000E+000	8.01181E+001	8.01181E+001	4.09000E-003	0.00000E+000	8.02203E+001
Off-Highway Trucks	4.00000E-005	1.80000E-004	1.48000E-003	0.00000E+000	1.00000E-005	1.00000E-005	0.00000E+000	2.89960E-001	2.89960E-001	9.00000E-005	0.00000E+000	2.92310E-001
Tractors/Loaders/Backhoes	1.38000E-003	5.97000E-003	8.49000E-002	1.10000E-004	1.80000E-004	1.80000E-004	0.00000E+000	9.89522E+000	9.89522E+000	3.20000E-003	0.00000E+000	9.97523E+000
Welders	3.18000E-003	1.58400E-002	1.80500E-002	3.00000E-005	7.80000E-004	7.80000E-004	0.00000E+000	1.97631E+000	1.97631E+000	2.60000E-004	0.00000E+000	1.98275E+000

Equipment Type	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Percent Reduction												
Air Compressors	8.64175E-001	9.15664E-001	-8.19230E-003	0.00000E+000	9.57834E-001	9.57834E-001	0.00000E+000	1.15099E-006	1.15099E-006	0.00000E+000	0.00000E+000	1.34052E-006
Bore/Drill Rigs	5.46125E-001	8.32388E-001	-1.06703E+000	0.00000E+000	8.33333E-001	8.20225E-001	0.00000E+000	1.15104E-006	1.15104E-006	0.00000E+000	0.00000E+000	1.14181E-006
Cement and Mortar Mixers	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000
Cranes	8.28349E-001	9.36653E-001	-3.10875E-001	0.00000E+000	9.51968E-001	9.47788E-001	0.00000E+000	1.16622E-006	1.16622E-006	0.00000E+000	0.00000E+000	1.15687E-006
Forklifts	8.54472E-001	9.30769E-001	5.37273E-003	0.00000E+000	9.70336E-001	9.67742E-001	0.00000E+000	9.73398E-007	9.73398E-007	0.00000E+000	0.00000E+000	9.65591E-007
Generator Sets	8.16028E-001	9.09982E-001	-1.00860E-001	0.00000E+000	9.47855E-001	9.47855E-001	0.00000E+000	1.24816E-006	1.24816E-006	0.00000E+000	0.00000E+000	1.24657E-006
Off-Highway Trucks	7.33333E-001	8.63636E-001	-6.44444E-001	0.00000E+000	8.00000E-001	7.50000E-001	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000
Tractors/Loaders/Backhoes	7.96760E-001	9.13126E-001	-3.62505E-002	0.00000E+000	9.55556E-001	9.51743E-001	0.00000E+000	1.01059E-006	1.01059E-006	0.00000E+000	0.00000E+000	1.00248E-006
Welders	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	5.05991E-006	5.05991E-006	0.00000E+000	0.00000E+000	0.00000E+000

Fugitive Dust Mitigation

Yes/No	Mitigation Measure	Mitigation Input		Mitigation Input		Mitigation Input	
No	Soil Stabilizer for unpaved Roads	PM10 Reduction	0.00	PM2.5 Reduction	0.00		
No	Replace Ground Cover of Area Disturbed	PM10 Reduction	0.00	PM2.5 Reduction	0.00		
Yes	Water Exposed Area	PM10 Reduction	61.00	PM2.5 Reduction	61.00	Frequency (per day)	3.00
No	Unpaved Road Mitigation	Moisture Content %	0.00	Vehicle Speed (mph)	0.00		
No	Clean Paved Road	% PM Reduction	0.00				

		Unmitigated		Mitigated		Percent Reduction	
Phase	Source	PM10	PM2.5	PM10	PM2.5	PM10	PM2.5
Burner Replacement	Fugitive Dust	0.00	0.00	0.00	0.00	0.00	0.00
Burner Replacement	Roads	0.01	0.00	0.01	0.00	0.00	0.00
Concrete Pour -Fuel Gas Cleaning Vessel Foundation	Fugitive Dust	0.00	0.00	0.00	0.00	0.00	0.00
Concrete Pour -Fuel Gas Cleaning Vessel Foundation	Roads	0.00	0.00	0.00	0.00	0.00	0.00
Demolition of existing Fuel Gas Cleaning Vessel	Fugitive Dust	0.00	0.00	0.00	0.00	0.60	1.00
Demolition of existing Fuel Gas Cleaning Vessel	Roads	0.00	0.00	0.00	0.00	0.00	0.00
Install Fuel Gas Cleaning Vessel	Fugitive Dust	0.00	0.00	0.00	0.00	0.00	0.00
Install Fuel Gas Cleaning Vessel	Roads	0.00	0.00	0.00	0.00	0.00	0.00
Scaffold Installation	Fugitive Dust	0.00	0.00	0.00	0.00	0.00	0.00
Scaffold Installation	Roads	0.00	0.00	0.00	0.00	0.00	0.00

Operational Percent Reduction Summary

Category	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Percent Reduction												
Architectural Coating	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Consumer Products	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hearth	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Landscaping	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mobile	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Indoor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Outdoor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Operational Mobile Mitigation

Project Setting:

Mitigation	Category	Measure	% Reduction	Input Value 1	Input Value 2	Input Value
No	Land Use	Increase Density	0.00			
No	Land Use	Increase Diversity	-0.01	0.13		
No	Land Use	Improve Walkability Design	0.00			
No	Land Use	Improve Destination Accessibility	0.00			
No	Land Use	Increase Transit Accessibility	0.25			
No	Land Use	Integrate Below Market Rate Housing	0.00			
	Land Use	Land Use SubTotal	0.00			

No	Neighborhood Enhancements	Improve Pedestrian Network				
No	Neighborhood Enhancements	Provide Traffic Calming Measures				
No	Neighborhood Enhancements	Implement NEV Network	0.00			
	Neighborhood Enhancements	Neighborhood Enhancements Subtotal	0.00			
No	Parking Policy Pricing	Limit Parking Supply	0.00			
No	Parking Policy Pricing	Unbundle Parking Costs	0.00			
No	Parking Policy Pricing	On-street Market Pricing	0.00			
	Parking Policy Pricing	Parking Policy Pricing Subtotal	0.00			
No	Transit Improvements	Provide BRT System	0.00			
No	Transit Improvements	Expand Transit Network	0.00			
No	Transit Improvements	Increase Transit Frequency	0.00			
	Transit Improvements	Transit Improvements Subtotal	0.00			
		Land Use and Site Enhancement Subtotal	0.00			
No	Commute	Implement Trip Reduction Program				
No	Commute	Transit Subsidy				
No	Commute	Implement Employee Parking "Cash Out"				
No	Commute	Workplace Parking Charge				
No	Commute	Encourage Telecommuting and Alternative Work Schedules	0.00			
No	Commute	Market Commute Trip Reduction Option	0.00			
No	Commute	Employee Vanpool/Shuttle	0.00		2.00	
No	Commute	Provide Ride Sharing Program				
	Commute	Commute Subtotal	0.00			

No	School Trip	Implement School Bus Program	0.00			
		Total VMT Reduction	0.00			

Area Mitigation

Measure Implemented	Mitigation Measure	Input Value
No	Only Natural Gas Hearth	
No	No Hearth	
No	Use Low VOC Cleaning Supplies	
No	Use Low VOC Paint (Residential Interior)	50.00
No	Use Low VOC Paint (Residential Exterior)	50.00
No	Use Low VOC Paint (Non-residential Interior)	100.00
No	Use Low VOC Paint (Non-residential Exterior)	100.00
No	Use Low VOC Paint (Parking)	100.00
No	% Electric Lawnmower	
No	% Electric Leafblower	
No	% Electric Chainsaw	

Energy Mitigation Measures

Measure Implemented	Mitigation Measure	Input Value 1	Input Value 2
No	Exceed Title 24		
No	Install High Efficiency Lighting		
No	On-site Renewable		

Appliance Type	Land Use Subtype	% Improvement
ClothWasher		30.00
DishWasher		15.00
Fan		50.00
Refrigerator		15.00

Water Mitigation Measures

Measure Implemented	Mitigation Measure	Input Value 1	Input Value 2
No	Apply Water Conservation on Strategy		
No	Use Reclaimed Water		
No	Use Grey Water		
No	Install low-flow bathroom faucet	32.00	
No	Install low-flow Kitchen faucet	18.00	
No	Install low-flow Toilet	20.00	
No	Install low-flow Shower	20.00	
No	Turf Reduction		
No	Use Water Efficient Irrigation Systems	6.10	
No	Water Efficient Landscape		

Solid Waste Mitigation

Mitigation Measures	Input Value

Institute Recycling and Composting Services Percent Reduction in Waste Disposed	

Construct New SCR-Boiler/Heater/GasTurbine

Los Angeles-South Coast County, Annual

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
Industrial Park	0.92	1000sqft	0.02	923.00	0

1.2 Other Project Characteristics

Urbanization	Urban	**Wind Speed (m/s)**	2.2	**Precipitation Freq (Days)**	33
Climate Zone	11			**Operational Year**	2021
Utility Company	Los Angeles Department of Water & Power				
CO2 Intensity (lb/MWhr)	1227.89	**CH4 Intensity (lb/MWhr)**	0.029	**N2O Intensity (lb/MWhr)**	0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics - Some facilities use SCE while others use LADWP, model here uses LADWP to generate conservative GHG values.

Land Use - Lot Acreage based on 2015 NOX RECLAIM ANALYSIS: one SCR for boiler/heater/turbine with a plot of 384 sq.ft + one 11,000-gallon ammonia tank with a plot of 539 sq.ft.

Construction Phase - 2015 NOx RECLAIM assumed 6 months of construction duration.

Off-road Equipment - Equipment list per 2015 NOx RECLAIM EA's Appendix E-2, added 1 off-highway truck to represent water truck, added Rubber Tired Dozer of 0 usage only to enable entry on next page.

Grading - Assume 3 feet cut for the 923 sq.ft plot (SCR+ammonia tank).

Trips and VMT - 20-worker crew (per 2015 NOx RECLAIM EA's Appendix E-2), assume 2 vendor trucks per day, and 1 haul truck per day (per 2015 NOX RECLAIM EA Appendix E-2, 1 ton/day of truck filling.

Energy Use -

Construction Off-road Equipment Mitigation - Tier 4 Final for all equip that is 50hp or greater.

Construct New SCR-Boiler/Heater/GasTurbine - Los Angeles-South Coast County, Annual

Table Name	Column Name	Default Value	New Value
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstructionPhase	NumDays	2.00	132.00
tblConstructionPhase	PhaseEndDate	6/23/2021	12/7/2021
tblConstructionPhase	PhaseStartDate	6/22/2021	6/7/2021
tblGrading	AcresOfGrading	0.00	0.21
tblGrading	MaterialExported	0.00	102.56
tblGrading	PhaseName		Grading
tblOffRoadEquipment	HorsePower	231.00	120.00
tblOffRoadEquipment	LoadFactor	0.20	0.20

tblOffRoadEquipment	LoadFactor	0.31	0.31
tblOffRoadEquipment	OffRoadEquipmentType		Rubber Tired Dozers
tblOffRoadEquipment	OffRoadEquipmentType		Cranes
tblOffRoadEquipment	OffRoadEquipmentType		Welders
tblOffRoadEquipment	OffRoadEquipmentType		Air Compressors
tblOffRoadEquipment	OffRoadEquipmentType		Plate Compactors
tblOffRoadEquipment	OffRoadEquipmentType		Forklifts
tblOffRoadEquipment	OffRoadEquipmentType		Pumps
tblOffRoadEquipment	OffRoadEquipmentType		Generator Sets
tblOffRoadEquipment	OffRoadEquipmentType		Aerial Lifts
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	UsageHours	1.00	0.00
tblOffRoadEquipment	UsageHours	8.00	2.00
tblOffRoadEquipment	UsageHours	6.00	4.00
tblTripsAndVMT	HaulingTripNumber	13.00	2.00
tblTripsAndVMT	VendorTripLength	6.90	50.00
tblTripsAndVMT	VendorTripNumber	0.00	4.00
tblTripsAndVMT	WorkerTripLength	14.70	25.00
tblTripsAndVMT	WorkerTripNumber	30.00	40.00

2.0 Emissions Summary

2.1 Overall Construction

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2021	0.1376	0.9792	1.0947	2.2800e-003	0.0613	0.0508	0.1122	0.0165	0.0490	0.0656	0.0000	198.8795	198.8795	0.0196	0.0000	199.3706
Maximum	**0.1376**	**0.9792**	**1.0947**	**2.2800e-003**	**0.0613**	**0.0508**	**0.1122**	**0.0165**	**0.0490**	**0.0656**	**0.0000**	**198.8795**	**198.8795**	**0.0196**	**0.0000**	**199.3706**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2021	0.0742	0.3793	1.1184	2.2800e-003	0.0613	0.0124	0.0736	0.0165	0.0123	0.0288	0.0000	198.8793	198.8793	0.0196	0.0000	199.3704
Maximum	**0.0742**	**0.3793**	**1.1184**	**2.2800e-003**	**0.0613**	**0.0124**	**0.0736**	**0.0165**	**0.0123**	**0.0288**	**0.0000**	**198.8793**	**198.8793**	**0.0196**	**0.0000**	**199.3704**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**46.08**	**61.26**	**-2.16**	**0.00**	**0.11**	**75.70**	**34.37**	**0.06**	**74.89**	**56.01**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Quarter	Start Date	End Date	Maximum Unmitigated ROG + NOX (tons/quarter)	Maximum Mitigated ROG + NOX (tons/quarter)
1	**6-7-2021**	**9-6-2021**	0.5528	0.2226
2	**9-7-2021**	**9-30-2021**	0.1442	0.0581
		Highest	0.5528	0.2226

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	3.7600e-003	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	2.0000e-005	2.0000e-005	0.0000	0.0000	2.0000e-005
Energy	5.0000e-005	4.7000e-004	4.0000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005	0.0000	7.1906	7.1906	1.7000e-004	4.0000e-005	7.2073
Mobile	1.7800e-003	9.4400e-003	0.0261	9.0000e-005	7.4400e-003	8.0000e-005	7.5200e-003	1.9900e-003	7.0000e-005	2.0700e-003	0.0000	8.4702	8.4702	4.5000e-004	0.0000	8.4814
Waste						0.0000	0.0000		0.0000	0.0000	0.2314	0.0000	0.2314	0.0137	0.0000	0.5733
Water						0.0000	0.0000		0.0000	0.0000	0.0675	1.5429	1.6104	6.9700e-003	1.7000e-004	1.8357
Total	**5.5900e-003**	**9.9100e-003**	**0.0265**	**9.0000e-005**	**7.4400e-003**	**1.2000e-004**	**7.5600e-003**	**1.9900e-003**	**1.1000e-004**	**2.1100e-003**	**0.2989**	**17.2037**	**17.5026**	**0.0213**	**2.1000e-004**	**18.0976**

2.2 Overall Operational

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	3.7600e-003	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	2.0000e-005	2.0000e-005	0.0000	0.0000	2.0000e-005
Energy	5.0000e-005	4.7000e-004	4.0000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005	0.0000	7.1906	7.1906	1.7000e-004	4.0000e-005	7.2073
Mobile	1.7800e-003	9.4400e-003	0.0261	9.0000e-005	7.4400e-003	8.0000e-005	7.5200e-003	1.9900e-003	7.0000e-005	2.0700e-003	0.0000	8.4702	8.4702	4.5000e-004	0.0000	8.4814
Waste						0.0000	0.0000		0.0000	0.0000	0.2314	0.0000	0.2314	0.0137	0.0000	0.5733
Water						0.0000	0.0000		0.0000	0.0000	0.0675	1.5429	1.6104	6.9700e-003	1.7000e-004	1.8357
Total	**5.5900e-003**	**9.9100e-003**	**0.0265**	**9.0000e-005**	**7.4400e-003**	**1.2000e-004**	**7.5600e-003**	**1.9900e-003**	**1.1000e-004**	**2.1100e-003**	**0.2989**	**17.2037**	**17.5026**	**0.0213**	**2.1000e-004**	**18.0976**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Grading	Grading	6/7/2021	12/7/2021	5	132	Grade both SCR plot and ammonia tank plot, plus construction structures

Acres of Grading (Site Preparation Phase): 0

Acres of Grading (Grading Phase): 0.21

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0; Striped Parking Area: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Grading	Rubber Tired Dozers	1	0.00	247	0.40
Grading	Cranes	1	8.00	120	0.29
Grading	Welders	2	8.00	46	0.45
Grading	Concrete/Industrial Saws	1	2.00	81	0.73
Grading	Air Compressors	1	1.00	78	0.48
Grading	Plate Compactors	1	4.00	8	0.43
Grading	Forklifts	1	3.00	89	0.20
Grading	Pumps	1	2.00	84	0.74
Grading	Generator Sets	1	8.00	84	0.74
Grading	Aerial Lifts	1	2.00	63	0.31
Grading	Tractors/Loaders/Backhoes	1	4.00	97	0.37

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Grading	12	40.00	4.00	2.00	25.00	50.00	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Use Cleaner Engines for Construction Equipment

Water Exposed Area

3.2 Grading - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					1.2000e-004	0.0000	1.2000e-004	1.0000e-005	0.0000	1.0000e-005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	0.1163	0.8702	0.9056	1.4000e-003		0.0501	0.0501		0.0483	0.0483	0.0000	116.2231	116.2231	0.0168	0.0000	116.6437
Total	**0.1163**	**0.8702**	**0.9056**	**1.4000e-003**	**1.2000e-004**	**0.0501**	**0.0502**	**1.0000e-005**	**0.0483**	**0.0483**	**0.0000**	**116.2231**	**116.2231**	**0.0168**	**0.0000**	**116.6437**

3.2 Grading - 2021

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category					tons/yr								MT/yr			
Hauling	1.0000e-005	2.8000e-004	6.0000e-005	0.0000	2.0000e-005	0.0000	2.0000e-005	0.0000	0.0000	1.0000e-005	0.0000	0.0762	0.0762	1.0000e-005	0.0000	0.0764
Vendor	3.6400e-003	0.0941	0.0269	4.0000e-004	0.0120	3.5000e-004	0.0124	3.4600e-003	3.3000e-004	3.7900e-003	0.0000	38.5518	38.5518	1.5400e-003	0.0000	38.5904
Worker	0.0176	0.0145	0.1621	4.9000e-004	0.0492	3.9000e-004	0.0496	0.0131	3.6000e-004	0.0134	0.0000	44.0284	44.0284	1.2700e-003	0.0000	44.0601
Total	**0.0213**	**0.1089**	**0.1891**	**8.9000e-004**	**0.0612**	**7.4000e-004**	**0.0619**	**0.0165**	**6.9000e-004**	**0.0172**	**0.0000**	**82.6564**	**82.6564**	**2.8200e-003**	**0.0000**	**82.7269**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category					tons/yr								MT/yr			
Fugitive Dust					5.0000e-005	0.0000	5.0000e-005	1.0000e-005	0.0000	1.0000e-005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	0.0529	0.2704	0.9293	1.4000e-003		0.0116	0.0116		0.0116	0.0116	0.0000	116.2230	116.2230	0.0168	0.0000	116.6436
Total	**0.0529**	**0.2704**	**0.9293**	**1.4000e-003**	**5.0000e-005**	**0.0116**	**0.0117**	**1.0000e-005**	**0.0116**	**0.0116**	**0.0000**	**116.2230**	**116.2230**	**0.0168**	**0.0000**	**116.6436**

3.2 Grading - 2021

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	1.0000e-005	2.8000e-004	6.0000e-005	0.0000	2.0000e-005	0.0000	2.0000e-005	0.0000	0.0000	1.0000e-005	0.0000	0.0762	0.0762	1.0000e-005	0.0000	0.0764
Vendor	3.6400e-003	0.0941	0.0269	4.0000e-004	0.0120	3.5000e-004	0.0124	3.4600e-003	3.3000e-004	3.7900e-003	0.0000	38.5518	38.5518	1.5400e-003	0.0000	38.5904
Worker	0.0176	0.0145	0.1621	4.9000e-004	0.0492	3.9000e-004	0.0496	0.0131	3.6000e-004	0.0134	0.0000	44.0284	44.0284	1.2700e-003	0.0000	44.0601
Total	**0.0213**	**0.1089**	**0.1891**	**8.9000e-004**	**0.0612**	**7.4000e-004**	**0.0619**	**0.0165**	**6.9000e-004**	**0.0172**	**0.0000**	**82.6564**	**82.6564**	**2.8200e-003**	**0.0000**	**82.7269**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

Construct New SCR-Boiler/Heater/GasTurbine - Los Angeles-South Coast County, Annual

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Mitigated	1.7800e-003	9.4400e-003	0.0261	9.0000e-005	7.4400e-003	8.0000e-005	7.5200e-003	1.9900e-003	7.0000e-005	2.0700e-003	0.0000	8.4702	8.4702	4.5000e-004	0.0000	8.4814
Unmitigated	1.7800e-003	9.4400e-003	0.0261	9.0000e-005	7.4400e-003	8.0000e-005	7.5200e-003	1.9900e-003	7.0000e-005	2.0700e-003	0.0000	8.4702	8.4702	4.5000e-004	0.0000	8.4814

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
Industrial Park	6.30	2.30	0.67	19,596	19,596
Total	6.30	2.30	0.67	19,596	19,596

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
Industrial Park	16.60	8.40	6.90	59.00	28.00	13.00	79	19	2

4.4 Fleet Mix

Land Use	LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
Industrial Park	0.547192	0.045177	0.202743	0.121510	0.016147	0.006143	0.019743	0.029945	0.002479	0.002270	0.005078	0.000682	0.000891

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Electricity Mitigated						0.0000	0.0000		0.0000	0.0000	0.0000	6.6778	6.6778	1.6000e-004	3.0000e-005	6.6915
Electricity Unmitigated						0.0000	0.0000		0.0000	0.0000	0.0000	6.6778	6.6778	1.6000e-004	3.0000e-005	6.6915
NaturalGas Mitigated	5.0000e-005	4.7000e-004	4.0000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005	0.0000	0.5127	0.5127	1.0000e-005	1.0000e-005	0.5158
NaturalGas Unmitigated	5.0000e-005	4.7000e-004	4.0000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005	0.0000	0.5127	0.5127	1.0000e-005	1.0000e-005	0.5158

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	tons/yr										MT/yr					
Industrial Park	9608.43	5.0000e-005	4.7000e-004	4.0000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005	0.0000	0.5127	0.5127	1.0000e-005	1.0000e-005	0.5158
Total		**5.0000e-005**	**4.7000e-004**	**4.0000e-004**	**0.0000**		**4.0000e-005**	**4.0000e-005**		**4.0000e-005**	**4.0000e-005**	**0.0000**	**0.5127**	**0.5127**	**1.0000e-005**	**1.0000e-005**	**0.5158**

5.2 Energy by Land Use - NaturalGas

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	tons/yr										MT/yr					
Industrial Park	9608.43	5.0000e-005	4.7000e-004	4.0000e-004	0.0000		4.0000e-005	4.0000e-005		4.0000e-005	4.0000e-005	0.0000	0.5127	0.5127	1.0000e-005	1.0000e-005	0.5158
Total		**5.0000e-005**	**4.7000e-004**	**4.0000e-004**	**0.0000**		**4.0000e-005**	**4.0000e-005**		**4.0000e-005**	**4.0000e-005**	**0.0000**	**0.5127**	**0.5127**	**1.0000e-005**	**1.0000e-005**	**0.5158**

5.3 Energy by Land Use - Electricity

Unmitigated

	Electricity Use	Total CO2	CH4	N2O	CO2e
Land Use	kWh/yr	MT/yr			
Industrial Park	11989.8	6.6778	1.6000e-004	3.0000e-005	6.6915
Total		**6.6778**	**1.6000e-004**	**3.0000e-005**	**6.6915**

5.3 Energy by Land Use - Electricity

<u>Mitigated</u>

	Electricity Use	Total CO2	CH4	N2O	CO2e
Land Use	kWh/yr	MT/yr			
Industrial Park	11989.8	6.6778	1.6000e-004	3.0000e-005	6.6915
Total		**6.6778**	**1.6000e-004**	**3.0000e-005**	**6.6915**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Mitigated	3.7600e-003	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	2.0000e-005	2.0000e-005	0.0000	0.0000	2.0000e-005
Unmitigated	3.7600e-003	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	2.0000e-005	2.0000e-005	0.0000	0.0000	2.0000e-005

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	tons/yr										MT/yr					
Architectural Coating	4.3000e-004					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Consumer Products	3.3400e-003					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Landscaping	0.0000	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	2.0000e-005	2.0000e-005	0.0000	0.0000	2.0000e-005
Total	**3.7700e-003**	**0.0000**	**1.0000e-005**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**2.0000e-005**	**2.0000e-005**	**0.0000**	**0.0000**	**2.0000e-005**

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	tons/yr										MT/yr					
Architectural Coating	4.3000e-004					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Consumer Products	3.3400e-003					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Landscaping	0.0000	0.0000	1.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	2.0000e-005	2.0000e-005	0.0000	0.0000	2.0000e-005
Total	**3.7700e-003**	**0.0000**	**1.0000e-005**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**2.0000e-005**	**2.0000e-005**	**0.0000**	**0.0000**	**2.0000e-005**

7.0 Water Detail

7.1 Mitigation Measures Water

	Total CO2	CH4	N2O	CO2e
Category	MT/yr			
Mitigated	1.6104	6.9700e-003	1.7000e-004	1.8357
Unmitigated	1.6104	6.9700e-003	1.7000e-004	1.8357

7.2 Water by Land Use

Unmitigated

	Indoor/Outdoor Use	Total CO2	CH4	N2O	CO2e
Land Use	Mgal	MT/yr			
Industrial Park	0.21275 / 0	1.6104	6.9700e-003	1.7000e-004	1.8357
Total		**1.6104**	**6.9700e-003**	**1.7000e-004**	**1.8357**

7.2 Water by Land Use

Mitigated

	Indoor/Outdoor Use	Total CO2	CH4	N2O	CO2e
Land Use	Mgal	MT/yr			
Industrial Park	0.21275 / 0	1.6104	6.9700e-003	1.7000e-004	1.8357
Total		**1.6104**	**6.9700e-003**	**1.7000e-004**	**1.8357**

8.0 Waste Detail

8.1 Mitigation Measures Waste

Category/Year

	Total CO2	CH4	N2O	CO2e
	MT/yr			
Mitigated	0.2314	0.0137	0.0000	0.5733
Unmitigated	0.2314	0.0137	0.0000	0.5733

8.2 Waste by Land Use

Unmitigated

	Waste Disposed	Total CO2	CH4	N2O	CO2e
Land Use	tons	MT/yr			
Industrial Park	1.14	0.2314	0.0137	0.0000	0.5733
Total		**0.2314**	**0.0137**	**0.0000**	**0.5733**

Mitigated

	Waste Disposed	Total CO2	CH4	N2O	CO2e
Land Use	tons	MT/yr			
Industrial Park	1.14	0.2314	0.0137	0.0000	0.5733
Total		**0.2314**	**0.0137**	**0.0000**	**0.5733**

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Stationary Equipment

Fire Pumps and Emergency Generators

Equipment Type	Number	Hours/Day	Hours/Year	Horse Power	Load Factor	Fuel Type

Boilers

Equipment Type	Number	Heat Input/Day	Heat Input/Year	Boiler Rating	Fuel Type

User Defined Equipment

Equipment Type	Number

11.0 Vegetation

Construct New SCR-Boiler/Heater/GasTurbine

Los Angeles-South Coast County, Summer

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
Industrial Park	0.92	1000sqft	0.02	923.00	0

1.2 Other Project Characteristics

Urbanization	Urban	**Wind Speed (m/s)**	2.2	**Precipitation Freq (Days)**	33
Climate Zone	11			**Operational Year**	2021
Utility Company	Los Angeles Department of Water & Power				
CO2 Intensity (lb/MWhr)	1227.89	**CH4 Intensity (lb/MWhr)**	0.029	**N2O Intensity (lb/MWhr)**	0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics - Some facilities use SCE while others use LADWP, model here uses LADWP to generate conservative GHG values.

Land Use - Lot Acreage based on 2015 NOX RECLAIM ANALYSIS: one SCR for boiler/heater/turbine with a plot of 384 sq.ft + one 11,000-gallon ammonia tank with a plot of 539 sq.ft.

Construction Phase - 2015 NOx RECLAIM assumed 6 months of construction duration.

Off-road Equipment - Equipment list per 2015 NOx RECLAIM EA's Appendix E-2, added 1 off-highway truck to represent water truck, added Rubber Tired Dozer of 0 usage only to enable entry on next page.

Grading - Assume 3 feet cut for the 923 sq.ft plot (SCR+ammonia tank).

Trips and VMT - 20-worker crew (per 2015 NOx RECLAIM EA's Appendix E-2), assume 2 vendor trucks per day, and 1 haul truck per day (per 2015 NOX RECLAIM EA Appendix E-2, 1 ton/day of truck filling.

Energy Use -

Construction Off-road Equipment Mitigation - Tier 4 Final for all equip that is 50hp or greater.

Construct New SCR-Boiler/Heater/GasTurbine - Los Angeles-South Coast County, Summer

Table Name	Column Name	Default Value	New Value
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstructionPhase	NumDays	2.00	132.00
tblConstructionPhase	PhaseEndDate	6/23/2021	12/7/2021
tblConstructionPhase	PhaseStartDate	6/22/2021	6/7/2021
tblGrading	AcresOfGrading	0.00	0.21
tblGrading	MaterialExported	0.00	102.56
tblGrading	PhaseName		Grading
tblOffRoadEquipment	HorsePower	231.00	120.00
tblOffRoadEquipment	LoadFactor	0.20	0.20

tblOffRoadEquipment	LoadFactor	0.31	0.31
tblOffRoadEquipment	OffRoadEquipmentType		Rubber Tired Dozers
tblOffRoadEquipment	OffRoadEquipmentType		Cranes
tblOffRoadEquipment	OffRoadEquipmentType		Welders
tblOffRoadEquipment	OffRoadEquipmentType		Air Compressors
tblOffRoadEquipment	OffRoadEquipmentType		Plate Compactors
tblOffRoadEquipment	OffRoadEquipmentType		Forklifts
tblOffRoadEquipment	OffRoadEquipmentType		Pumps
tblOffRoadEquipment	OffRoadEquipmentType		Generator Sets
tblOffRoadEquipment	OffRoadEquipmentType		Aerial Lifts
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	UsageHours	1.00	0.00
tblOffRoadEquipment	UsageHours	8.00	2.00
tblOffRoadEquipment	UsageHours	6.00	4.00
tblTripsAndVMT	HaulingTripNumber	13.00	2.00
tblTripsAndVMT	VendorTripLength	6.90	50.00
tblTripsAndVMT	VendorTripNumber	0.00	4.00
tblTripsAndVMT	WorkerTripLength	14.70	25.00
tblTripsAndVMT	WorkerTripNumber	30.00	40.00

2.0 Emissions Summary

2.1 Overall Construction (Maximum Daily Emission)

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2021	2.0799	14.7451	16.7661	0.0349	0.9471	0.7702	1.7172	0.2550	0.7427	0.9977	0.0000	3,355.918 3	3,355.918 3	0.3290	0.0000	3,364.142 7
Maximum	**2.0799**	**14.7451**	**16.7661**	**0.0349**	**0.9471**	**0.7702**	**1.7172**	**0.2550**	**0.7427**	**0.9977**	**0.0000**	**3,355.918 3**	**3,355.918 3**	**0.3290**	**0.0000**	**3,364.142 7**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2021	1.1192	5.6563	17.1247	0.0349	0.9460	0.1871	1.1331	0.2549	0.1864	0.4413	0.0000	3,355.918 3	3,355.918 3	0.3290	0.0000	3,364.142 7
Maximum	**1.1192**	**5.6563**	**17.1247**	**0.0349**	**0.9460**	**0.1871**	**1.1331**	**0.2549**	**0.1864**	**0.4413**	**0.0000**	**3,355.918 3**	**3,355.918 3**	**0.3290**	**0.0000**	**3,364.142 7**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**46.19**	**61.64**	**-2.14**	**0.00**	**0.12**	**75.70**	**34.02**	**0.05**	**74.90**	**55.77**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	0.0206	0.0000	9.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-004	2.0000e-004	0.0000		2.2000e-004
Energy	2.8000e-004	2.5800e-003	2.1700e-003	2.0000e-005		2.0000e-004	2.0000e-004		2.0000e-004	2.0000e-004		3.0970	3.0970	6.0000e-005	6.0000e-005	3.1154
Mobile	0.0131	0.0633	0.1915	6.7000e-004	0.0533	5.5000e-004	0.0539	0.0143	5.1000e-004	0.0148		68.0154	68.0154	3.4900e-003		68.1026
Total	**0.0341**	**0.0659**	**0.1938**	**6.9000e-004**	**0.0533**	**7.5000e-004**	**0.0541**	**0.0143**	**7.1000e-004**	**0.0150**		**71.1126**	**71.1126**	**3.5500e-003**	**6.0000e-005**	**71.2183**

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	0.0206	0.0000	9.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-004	2.0000e-004	0.0000		2.2000e-004
Energy	2.8000e-004	2.5800e-003	2.1700e-003	2.0000e-005		2.0000e-004	2.0000e-004		2.0000e-004	2.0000e-004		3.0970	3.0970	6.0000e-005	6.0000e-005	3.1154
Mobile	0.0131	0.0633	0.1915	6.7000e-004	0.0533	5.5000e-004	0.0539	0.0143	5.1000e-004	0.0148		68.0154	68.0154	3.4900e-003		68.1026
Total	**0.0341**	**0.0659**	**0.1938**	**6.9000e-004**	**0.0533**	**7.5000e-004**	**0.0541**	**0.0143**	**7.1000e-004**	**0.0150**		**71.1126**	**71.1126**	**3.5500e-003**	**6.0000e-005**	**71.2183**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Grading	Grading	6/7/2021	12/7/2021	5	132	Grade both SCR plot and ammonia tank plot, plus construction structures

Acres of Grading (Site Preparation Phase): 0

Acres of Grading (Grading Phase): 0.21

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0; Striped Parking Area: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Grading	Rubber Tired Dozers	1	0.00	247	0.40
Grading	Cranes	1	8.00	120	0.29
Grading	Welders	2	8.00	46	0.45
Grading	Concrete/Industrial Saws	1	2.00	81	0.73
Grading	Air Compressors	1	1.00	78	0.48
Grading	Plate Compactors	1	4.00	8	0.43
Grading	Forklifts	1	3.00	89	0.20
Grading	Pumps	1	2.00	84	0.74
Grading	Generator Sets	1	8.00	84	0.74
Grading	Aerial Lifts	1	2.00	63	0.31
Grading	Tractors/Loaders/Backhoes	1	4.00	97	0.37

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Grading	12	40.00	4.00	2.00	25.00	50.00	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Use Cleaner Engines for Construction Equipment

Water Exposed Area

3.2 Grading - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					1.7800e-003	0.0000	1.7800e-003	2.0000e-004	0.0000	2.0000e-004			0.0000			0.0000
Off-Road	1.7621	13.1850	13.7214	0.0212		0.7589	0.7589		0.7321	0.7321		1,941.1218	1,941.1218	0.2810		1,948.1464
Total	**1.7621**	**13.1850**	**13.7214**	**0.0212**	**1.7800e-003**	**0.7589**	**0.7607**	**2.0000e-004**	**0.7321**	**0.7323**		**1,941.1218**	**1,941.1218**	**0.2810**		**1,948.1464**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	1.3000e-004	4.0600e-003	9.5000e-004	1.0000e-005	2.6000e-004	1.0000e-005	2.8000e-004	7.0000e-005	1.0000e-005	8.0000e-005		1.2825	1.2825	9.0000e-005		1.2847
Vendor	0.0548	1.3627	0.4045	6.0400e-003	0.1849	5.2600e-003	0.1902	0.0532	5.0300e-003	0.0582		645.1456	645.1456	0.0256		645.7863
Worker	0.2629	0.1933	2.6393	7.7100e-003	0.7601	5.9700e-003	0.7661	0.2016	5.5000e-003	0.2070		768.3684	768.3684	0.0223		768.9253
Total	**0.3178**	**1.5601**	**3.0448**	**0.0138**	**0.9453**	**0.0112**	**0.9565**	**0.2548**	**0.0105**	**0.2653**		**1,414.7965**	**1,414.7965**	**0.0480**		**1,415.9963**

3.2 Grading - 2021

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					6.9000e-004	0.0000	6.9000e-004	8.0000e-005	0.0000	8.0000e-005			0.0000			0.0000
Off-Road	0.8014	4.0962	14.0799	0.0212		0.1759	0.1759		0.1759	0.1759	0.0000	1,941.1218	1,941.1218	0.2810		1,948.1464
Total	**0.8014**	**4.0962**	**14.0799**	**0.0212**	**6.9000e-004**	**0.1759**	**0.1766**	**8.0000e-005**	**0.1759**	**0.1760**	**0.0000**	**1,941.1218**	**1,941.1218**	**0.2810**		**1,948.1464**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	1.3000e-004	4.0600e-003	9.5000e-004	1.0000e-005	2.6000e-004	1.0000e-005	2.8000e-004	7.0000e-005	1.0000e-005	8.0000e-005		1.2825	1.2825	9.0000e-005		1.2847
Vendor	0.0548	1.3627	0.4045	6.0400e-003	0.1849	5.2600e-003	0.1902	0.0532	5.0300e-003	0.0582		645.1456	645.1456	0.0256		645.7863
Worker	0.2629	0.1933	2.6393	7.7100e-003	0.7601	5.9700e-003	0.7661	0.2016	5.5000e-003	0.2070		768.3684	768.3684	0.0223		768.9253
Total	**0.3178**	**1.5601**	**3.0448**	**0.0138**	**0.9453**	**0.0112**	**0.9565**	**0.2548**	**0.0105**	**0.2653**		**1,414.7965**	**1,414.7965**	**0.0480**		**1,415.9963**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	0.0131	0.0633	0.1915	6.7000e-004	0.0533	5.5000e-004	0.0539	0.0143	5.1000e-004	0.0148		68.0154	68.0154	3.4900e-003		68.1026
Unmitigated	0.0131	0.0633	0.1915	6.7000e-004	0.0533	5.5000e-004	0.0539	0.0143	5.1000e-004	0.0148		68.0154	68.0154	3.4900e-003		68.1026

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
Industrial Park	6.30	2.30	0.67	19,596	19,596
Total	6.30	2.30	0.67	19,596	19,596

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
Industrial Park	16.60	8.40	6.90	59.00	28.00	13.00	79	19	2

4.4 Fleet Mix

Land Use	LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
Industrial Park	0.547192	0.045177	0.202743	0.121510	0.016147	0.006143	0.019743	0.029945	0.002479	0.002270	0.005078	0.000682	0.000891

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
NaturalGas Mitigated	2.8000e-004	2.5800e-003	2.1700e-003	2.0000e-005		2.0000e-004	2.0000e-004		2.0000e-004	2.0000e-004		3.0970	3.0970	6.0000e-005	6.0000e-005	3.1154
NaturalGas Unmitigated	2.8000e-004	2.5800e-003	2.1700e-003	2.0000e-005		2.0000e-004	2.0000e-004		2.0000e-004	2.0000e-004		3.0970	3.0970	6.0000e-005	6.0000e-005	3.1154

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
Industrial Park	26.3245	2.8000e-004	2.5800e-003	2.1700e-003	2.0000e-005		2.0000e-004	2.0000e-004		2.0000e-004	2.0000e-004		3.0970	3.0970	6.0000e-005	6.0000e-005	3.1154
Total		**2.8000e-004**	**2.5800e-003**	**2.1700e-003**	**2.0000e-005**		**2.0000e-004**	**2.0000e-004**		**2.0000e-004**	**2.0000e-004**		**3.0970**	**3.0970**	**6.0000e-005**	**6.0000e-005**	**3.1154**

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
Industrial Park	0.0263245	2.8000e-004	2.5800e-003	2.1700e-003	2.0000e-005		2.0000e-004	2.0000e-004		2.0000e-004	2.0000e-004		3.0970	3.0970	6.0000e-005	6.0000e-005	3.1154
Total		**2.8000e-004**	**2.5800e-003**	**2.1700e-003**	**2.0000e-005**		**2.0000e-004**	**2.0000e-004**		**2.0000e-004**	**2.0000e-004**		**3.0970**	**3.0970**	**6.0000e-005**	**6.0000e-005**	**3.1154**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	0.0206	0.0000	9.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-004	2.0000e-004	0.0000		2.2000e-004
Unmitigated	0.0206	0.0000	9.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-004	2.0000e-004	0.0000		2.2000e-004

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	2.3500e-003					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.0183					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	1.0000e-005	0.0000	9.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-004	2.0000e-004	0.0000		2.2000e-004
Total	**0.0206**	**0.0000**	**9.0000e-005**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**2.0000e-004**	**2.0000e-004**	**0.0000**		**2.2000e-004**

6.2 Area by SubCategory

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	2.3500e-003					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.0183					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	1.0000e-005	0.0000	9.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-004	2.0000e-004	0.0000		2.2000e-004
Total	**0.0206**	**0.0000**	**9.0000e-005**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**2.0000e-004**	**2.0000e-004**	**0.0000**		**2.2000e-004**

7.0 Water Detail

7.1 Mitigation Measures Water

8.0 Waste Detail

8.1 Mitigation Measures Waste

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Stationary Equipment

Fire Pumps and Emergency Generators

Equipment Type	Number	Hours/Day	Hours/Year	Horse Power	Load Factor	Fuel Type

Boilers

Equipment Type	Number	Heat Input/Day	Heat Input/Year	Boiler Rating	Fuel Type

User Defined Equipment

Equipment Type	Number

11.0 Vegetation

Construct New SCR-Boiler/Heater/GasTurbine

Los Angeles-South Coast County, Winter

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
Industrial Park	0.92	1000sqft	0.02	923.00	0

1.2 Other Project Characteristics

Urbanization	Urban	**Wind Speed (m/s)**	2.2	**Precipitation Freq (Days)**	33
Climate Zone	11			**Operational Year**	2021
Utility Company	Los Angeles Department of Water & Power				
CO2 Intensity (lb/MWhr)	1227.89	**CH4 Intensity (lb/MWhr)**	0.029	**N2O Intensity (lb/MWhr)**	0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics - Some facilities use SCE while others use LADWP, model here uses LADWP to generate conservative GHG values.

Land Use - Lot Acreage based on 2015 NOX RECLAIM ANALYSIS: one SCR for boiler/heater/turbine with a plot of 384 sq.ft + one 11,000-gallon ammonia tank with a plot of 539 sq.ft.

Construction Phase - 2015 NOx RECLAIM assumed 6 months of construction duration.

Off-road Equipment - Equipment list per 2015 NOx RECLAIM EA's Appendix E-2, added 1 off-highway truck to represent water truck, added Rubber Tired Dozer of 0 usage only to enable entry on next page.

Grading - Assume 3 feet cut for the 923 sq.ft plot (SCR+ammonia tank).

Trips and VMT - 20-worker crew (per 2015 NOx RECLAIM EA's Appendix E-2), assume 2 vendor trucks per day, and 1 haul truck per day (per 2015 NOX RECLAIM EA Appendix E-2, 1 ton/day of truck filling.

Energy Use -

Construction Off-road Equipment Mitigation - Tier 4 Final for all equip that is 50hp or greater.

Construct New SCR-Boiler/Heater/GasTurbine - Los Angeles-South Coast County, Winter

Table Name	Column Name	Default Value	New Value
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstructionPhase	NumDays	2.00	132.00
tblConstructionPhase	PhaseEndDate	6/23/2021	12/7/2021
tblConstructionPhase	PhaseStartDate	6/22/2021	6/7/2021
tblGrading	AcresOfGrading	0.00	0.21
tblGrading	MaterialExported	0.00	102.56
tblGrading	PhaseName		Grading
tblOffRoadEquipment	HorsePower	231.00	120.00
tblOffRoadEquipment	LoadFactor	0.20	0.20

Construct New SCR-Boiler/Heater/GasTurbine - Los Angeles-South Coast County, Winter

tblOffRoadEquipment	LoadFactor	0.31	0.31
tblOffRoadEquipment	OffRoadEquipmentType		Rubber Tired Dozers
tblOffRoadEquipment	OffRoadEquipmentType		Cranes
tblOffRoadEquipment	OffRoadEquipmentType		Welders
tblOffRoadEquipment	OffRoadEquipmentType		Air Compressors
tblOffRoadEquipment	OffRoadEquipmentType		Plate Compactors
tblOffRoadEquipment	OffRoadEquipmentType		Forklifts
tblOffRoadEquipment	OffRoadEquipmentType		Pumps
tblOffRoadEquipment	OffRoadEquipmentType		Generator Sets
tblOffRoadEquipment	OffRoadEquipmentType		Aerial Lifts
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	UsageHours	1.00	0.00
tblOffRoadEquipment	UsageHours	8.00	2.00
tblOffRoadEquipment	UsageHours	6.00	4.00
tblTripsAndVMT	HaulingTripNumber	13.00	2.00
tblTripsAndVMT	VendorTripLength	6.90	50.00
tblTripsAndVMT	VendorTripNumber	0.00	4.00
tblTripsAndVMT	WorkerTripLength	14.70	25.00
tblTripsAndVMT	WorkerTripNumber	30.00	40.00

2.0 Emissions Summary

2.1 Overall Construction (Maximum Daily Emission)

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2021	2.1161	14.8041	16.5201	0.0345	0.9471	0.7702	1.7173	0.2550	0.7427	0.9977	0.0000	3,307.7571	3,307.7571	0.3279	0.0000	3,315.9557
Maximum	**2.1161**	**14.8041**	**16.5201**	**0.0345**	**0.9471**	**0.7702**	**1.7173**	**0.2550**	**0.7427**	**0.9977**	**0.0000**	**3,307.7571**	**3,307.7571**	**0.3279**	**0.0000**	**3,315.9557**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2021	1.1554	5.7153	16.8787	0.0345	0.9460	0.1872	1.1331	0.2549	0.1865	0.4413	0.0000	3,307.7571	3,307.7571	0.3279	0.0000	3,315.9557
Maximum	**1.1554**	**5.7153**	**16.8787**	**0.0345**	**0.9460**	**0.1872**	**1.1331**	**0.2549**	**0.1865**	**0.4413**	**0.0000**	**3,307.7571**	**3,307.7571**	**0.3279**	**0.0000**	**3,315.9557**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**45.40**	**61.39**	**-2.17**	**0.00**	**0.12**	**75.70**	**34.01**	**0.05**	**74.90**	**55.77**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	0.0206	0.0000	9.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-004	2.0000e-004	0.0000		2.2000e-004
Energy	2.8000e-004	2.5800e-003	2.1700e-003	2.0000e-005		2.0000e-004	2.0000e-004		2.0000e-004	2.0000e-004		3.0970	3.0970	6.0000e-005	6.0000e-005	3.1154
Mobile	0.0128	0.0651	0.1808	6.4000e-004	0.0533	5.5000e-004	0.0539	0.0143	5.1000e-004	0.0148		64.7460	64.7460	3.4600e-003		64.8325
Total	**0.0337**	**0.0677**	**0.1830**	**6.6000e-004**	**0.0533**	**7.5000e-004**	**0.0541**	**0.0143**	**7.1000e-004**	**0.0150**		**67.8432**	**67.8432**	**3.5200e-003**	**6.0000e-005**	**67.9482**

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	0.0206	0.0000	9.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-004	2.0000e-004	0.0000		2.2000e-004
Energy	2.8000e-004	2.5800e-003	2.1700e-003	2.0000e-005		2.0000e-004	2.0000e-004		2.0000e-004	2.0000e-004		3.0970	3.0970	6.0000e-005	6.0000e-005	3.1154
Mobile	0.0128	0.0651	0.1808	6.4000e-004	0.0533	5.5000e-004	0.0539	0.0143	5.1000e-004	0.0148		64.7460	64.7460	3.4600e-003		64.8325
Total	**0.0337**	**0.0677**	**0.1830**	**6.6000e-004**	**0.0533**	**7.5000e-004**	**0.0541**	**0.0143**	**7.1000e-004**	**0.0150**		**67.8432**	**67.8432**	**3.5200e-003**	**6.0000e-005**	**67.9482**

Construct New SCR-Boiler/Heater/GasTurbine - Los Angeles-South Coast County, Winter

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

3.0 Construction Detail

<u>Construction Phase</u>

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Grading	Grading	6/7/2021	12/7/2021	5	132	Grade both SCR plot and ammonia tank plot, plus construction structures

Acres of Grading (Site Preparation Phase): 0

Acres of Grading (Grading Phase): 0.21

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0; Striped Parking Area: 0 (Architectural Coating – sqft)

<u>OffRoad Equipment</u>

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Grading	Rubber Tired Dozers	1	0.00	247	0.40
Grading	Cranes	1	8.00	120	0.29
Grading	Welders	2	8.00	46	0.45
Grading	Concrete/Industrial Saws	1	2.00	81	0.73
Grading	Air Compressors	1	1.00	78	0.48
Grading	Plate Compactors	1	4.00	8	0.43
Grading	Forklifts	1	3.00	89	0.20
Grading	Pumps	1	2.00	84	0.74
Grading	Generator Sets	1	8.00	84	0.74
Grading	Aerial Lifts	1	2.00	63	0.31
Grading	Tractors/Loaders/Backhoes	1	4.00	97	0.37

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Grading	12	40.00	4.00	2.00	25.00	50.00	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Use Cleaner Engines for Construction Equipment

Water Exposed Area

3.2 Grading - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					1.7800e-003	0.0000	1.7800e-003	2.0000e-004	0.0000	2.0000e-004			0.0000			0.0000
Off-Road	1.7621	13.1850	13.7214	0.0212		0.7589	0.7589		0.7321	0.7321		1,941.1218	1,941.1218	0.2810		1,948.1464
Total	**1.7621**	**13.1850**	**13.7214**	**0.0212**	**1.7800e-003**	**0.7589**	**0.7607**	**2.0000e-004**	**0.7321**	**0.7323**		**1,941.1218**	**1,941.1218**	**0.2810**		**1,948.1464**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	1.3000e-004	4.1100e-003	1.0100e-003	1.0000e-005	2.6000e-004	1.0000e-005	2.8000e-004	7.0000e-005	1.0000e-005	8.0000e-005		1.2603	1.2603	9.0000e-005		1.2625
Vendor	0.0560	1.4009	0.4124	6.0200e-003	0.1849	5.2900e-003	0.1902	0.0532	5.0600e-003	0.0582		642.1316	642.1316	0.0260		642.7822
Worker	0.2979	0.2141	2.3854	7.2600e-003	0.7601	5.9700e-003	0.7661	0.2016	5.5000e-003	0.2070		723.2435	723.2435	0.0209		723.7646
Total	**0.3540**	**1.6191**	**2.7988**	**0.0133**	**0.9453**	**0.0113**	**0.9566**	**0.2548**	**0.0106**	**0.2654**		**1,366.6354**	**1,366.6354**	**0.0470**		**1,367.8093**

3.2 Grading - 2021

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					6.9000e-004	0.0000	6.9000e-004	8.0000e-005	0.0000	8.0000e-005			0.0000			0.0000
Off-Road	0.8014	4.0962	14.0799	0.0212		0.1759	0.1759		0.1759	0.1759	0.0000	1,941.1218	1,941.1218	0.2810		1,948.1464
Total	**0.8014**	**4.0962**	**14.0799**	**0.0212**	**6.9000e-004**	**0.1759**	**0.1766**	**8.0000e-005**	**0.1759**	**0.1760**	**0.0000**	**1,941.1218**	**1,941.1218**	**0.2810**		**1,948.1464**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	1.3000e-004	4.1100e-003	1.0100e-003	1.0000e-005	2.6000e-004	1.0000e-005	2.8000e-004	7.0000e-005	1.0000e-005	8.0000e-005		1.2603	1.2603	9.0000e-005		1.2625
Vendor	0.0560	1.4009	0.4124	6.0200e-003	0.1849	5.2900e-003	0.1902	0.0532	5.0600e-003	0.0582		642.1316	642.1316	0.0260		642.7822
Worker	0.2979	0.2141	2.3854	7.2600e-003	0.7601	5.9700e-003	0.7661	0.2016	5.5000e-003	0.2070		723.2435	723.2435	0.0209		723.7646
Total	**0.3540**	**1.6191**	**2.7988**	**0.0133**	**0.9453**	**0.0113**	**0.9566**	**0.2548**	**0.0106**	**0.2654**		**1,366.6354**	**1,366.6354**	**0.0470**		**1,367.8093**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	0.0128	0.0651	0.1808	6.4000e-004	0.0533	5.5000e-004	0.0539	0.0143	5.1000e-004	0.0148		64.7460	64.7460	3.4600e-003		64.8325
Unmitigated	0.0128	0.0651	0.1808	6.4000e-004	0.0533	5.5000e-004	0.0539	0.0143	5.1000e-004	0.0148		64.7460	64.7460	3.4600e-003		64.8325

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
Industrial Park	6.30	2.30	0.67	19,596	19,596
Total	6.30	2.30	0.67	19,596	19,596

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
Industrial Park	16.60	8.40	6.90	59.00	28.00	13.00	79	19	2

4.4 Fleet Mix

Land Use	LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
Industrial Park	0.547192	0.045177	0.202743	0.121510	0.016147	0.006143	0.019743	0.029945	0.002479	0.002270	0.005078	0.000682	0.000891

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
NaturalGas Mitigated	2.8000e-004	2.5800e-003	2.1700e-003	2.0000e-005		2.0000e-004	2.0000e-004		2.0000e-004	2.0000e-004		3.0970	3.0970	6.0000e-005	6.0000e-005	3.1154
NaturalGas Unmitigated	2.8000e-004	2.5800e-003	2.1700e-003	2.0000e-005		2.0000e-004	2.0000e-004		2.0000e-004	2.0000e-004		3.0970	3.0970	6.0000e-005	6.0000e-005	3.1154

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
Industrial Park	26.3245	2.8000e-004	2.5800e-003	2.1700e-003	2.0000e-005		2.0000e-004	2.0000e-004		2.0000e-004	2.0000e-004		3.0970	3.0970	6.0000e-005	6.0000e-005	3.1154
Total		**2.8000e-004**	**2.5800e-003**	**2.1700e-003**	**2.0000e-005**		**2.0000e-004**	**2.0000e-004**		**2.0000e-004**	**2.0000e-004**		**3.0970**	**3.0970**	**6.0000e-005**	**6.0000e-005**	**3.1154**

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
Industrial Park	0.0263245	2.8000e-004	2.5800e-003	2.1700e-003	2.0000e-005		2.0000e-004	2.0000e-004		2.0000e-004	2.0000e-004		3.0970	3.0970	6.0000e-005	6.0000e-005	3.1154
Total		**2.8000e-004**	**2.5800e-003**	**2.1700e-003**	**2.0000e-005**		**2.0000e-004**	**2.0000e-004**		**2.0000e-004**	**2.0000e-004**		**3.0970**	**3.0970**	**6.0000e-005**	**6.0000e-005**	**3.1154**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	0.0206	0.0000	9.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-004	2.0000e-004	0.0000		2.2000e-004
Unmitigated	0.0206	0.0000	9.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-004	2.0000e-004	0.0000		2.2000e-004

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	2.3500e-003					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.0183					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	1.0000e-005	0.0000	9.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-004	2.0000e-004	0.0000		2.2000e-004
Total	**0.0206**	**0.0000**	**9.0000e-005**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**2.0000e-004**	**2.0000e-004**	**0.0000**		**2.2000e-004**

6.2 Area by SubCategory

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	2.3500e-003					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.0183					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	1.0000e-005	0.0000	9.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000		2.0000e-004	2.0000e-004	0.0000		2.2000e-004
Total	**0.0206**	**0.0000**	**9.0000e-005**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**2.0000e-004**	**2.0000e-004**	**0.0000**		**2.2000e-004**

7.0 Water Detail

7.1 Mitigation Measures Water

8.0 Waste Detail

8.1 Mitigation Measures Waste

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Stationary Equipment

Fire Pumps and Emergency Generators

Equipment Type	Number	Hours/Day	Hours/Year	Horse Power	Load Factor	Fuel Type

Boilers

Equipment Type	Number	Heat Input/Day	Heat Input/Year	Boiler Rating	Fuel Type

User Defined Equipment

Equipment Type	Number

11.0 Vegetation

Construct New SCR-Boiler/Heater/GasTurbine

Los Angeles-South Coast County, Mitigation Report

Construction Mitigation Summary

Phase	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio-CO2	Total CO2	CH4	N2O	CO2e
Percent Reduction												
Grading	0.46	0.61	-0.02	0.00	0.76	0.75	0.00	0.00	0.00	0.00	0.00	0.00

OFFROAD Equipment Mitigation

Equipment Type	Fuel Type	Tier	Number Mitigated	Total Number of Equipment	DPF	Oxidation Catalyst
Rubber Tired Dozers	Diesel	Tier 4 Final	1	1	No Change	0.00
Cranes	Diesel	Tier 4 Final	1	1	No Change	0.00
Concrete/Industrial Saws	Diesel	Tier 4 Final	1	1	No Change	0.00
Aerial Lifts	Diesel	Tier 4 Final	1	1	No Change	0.00
Air Compressors	Diesel	Tier 4 Final	1	1	No Change	0.00
Forklifts	Diesel	Tier 4 Final	1	1	No Change	0.00
Generator Sets	Diesel	Tier 4 Final	1	1	No Change	0.00
Plate Compactors	Diesel	No Change	0	1	No Change	0.00
Pumps	Diesel	Tier 4 Final	1	1	No Change	0.00
Tractors/Loaders/Backhoes	Diesel	Tier 4 Final	1	1	No Change	0.00
Welders	Diesel	No Change	0	2	No Change	0.00

CalEEMod Version: CalEEMod.2016.3.2 Page 2 of 9 Date: 1/12/2021 4:40 PM

Equipment Type	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	Unmitigated tons/yr						Unmitigated mt/yr					
Aerial Lifts	6.10000E-004	9.85000E-003	1.79500E-002	3.00000E-005	1.90000E-004	1.70000E-004	0.00000E+000	2.42005E+000	2.42005E+000	7.80000E-004	0.00000E+000	2.43962E+000
Air Compressors	2.41000E-003	1.68000E-002	1.99900E-002	3.00000E-005	1.04000E-003	1.04000E-003	0.00000E+000	2.80858E+000	2.80858E+000	1.90000E-004	0.00000E+000	2.81340E+000
Concrete/Industrial Saws	6.35000E-003	5.01300E-002	6.06200E-002	1.00000E-004	2.86000E-003	2.86000E-003	0.00000E+000	8.87133E+000	8.87133E+000	5.20000E-004	0.00000E+000	8.88421E+000
Cranes	2.63900E-002	2.32150E-001	1.64670E-001	2.00000E-004	1.61300E-002	1.48400E-002	0.00000E+000	1.72678E+001	1.72678E+001	5.58000E-003	0.00000E+000	1.74074E+001
Forklifts	3.22000E-003	2.93300E-002	2.90500E-002	4.00000E-005	2.08000E-003	1.92000E-003	0.00000E+000	3.34033E+000	3.34033E+000	1.08000E-003	0.00000E+000	3.36734E+000
Generator Sets	2.35900E-002	2.08970E-001	2.43190E-001	4.30000E-004	1.10700E-002	1.10700E-002	0.00000E+000	3.73037E+001	3.73037E+001	1.90000E-003	0.00000E+000	3.73513E+001
Plate Compactors	1.32000E-003	8.29000E-003	6.95000E-003	2.00000E-005	3.20000E-004	3.20000E-004	0.00000E+000	1.03221E+000	1.03221E+000	1.10000E-004	0.00000E+000	1.03489E+000
Pumps	6.28000E-003	5.29700E-002	6.17200E-002	1.10000E-004	2.93000E-003	2.93000E-003	0.00000E+000	9.32594E+000	9.32594E+000	5.10000E-004	0.00000E+000	9.33866E+000
Rubber Tired Dozers	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000
Tractors/Loaders/Backhoes	6.18000E-003	6.25600E-002	7.45900E-002	1.00000E-004	3.69000E-003	3.39000E-003	0.00000E+000	9.00807E+000	9.00807E+000	2.91000E-003	0.00000E+000	9.08091E+000
Welders	3.99500E-002	1.99170E-001	2.26880E-001	3.40000E-004	9.78000E-003	9.78000E-003	0.00000E+000	2.48451E+001	2.48451E+001	3.24000E-003	0.00000E+000	2.49260E+001

Equipment Type	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	Mitigated tons/yr						Mitigated mt/yr					
Aerial Lifts	6.80000E-004	1.54800E-002	2.09100E-002	3.00000E-005	5.00000E-005	5.00000E-005	0.00000E+000	2.42005E+000	2.42005E+000	7.80000E-004	0.00000E+000	2.43961E+000
Air Compressors	3.30000E-004	1.42000E-003	2.01600E-002	3.00000E-005	4.00000E-005	4.00000E-005	0.00000E+000	2.80858E+000	2.80858E+000	1.90000E-004	0.00000E+000	2.81339E+000
Concrete/Industrial Saws	1.03000E-003	4.47000E-003	6.36700E-002	1.00000E-004	1.40000E-004	1.40000E-004	0.00000E+000	8.87132E+000	8.87132E+000	5.20000E-004	0.00000E+000	8.88420E+000
Cranes	2.43000E-003	1.05300E-002	1.49880E-001	2.00000E-004	3.20000E-004	3.20000E-004	0.00000E+000	1.72678E+001	1.72678E+001	5.58000E-003	0.00000E+000	1.74074E+001
Forklifts	4.70000E-004	2.03000E-003	2.88900E-002	4.00000E-005	6.00000E-005	6.00000E-005	0.00000E+000	3.34032E+000	3.34032E+000	1.08000E-003	0.00000E+000	3.36733E+000
Generator Sets	4.34000E-003	1.88100E-002	2.67720E-001	4.30000E-004	5.80000E-004	5.80000E-004	0.00000E+000	3.73037E+001	3.73037E+001	1.90000E-003	0.00000E+000	3.73512E+001
Plate Compactors	1.32000E-003	8.29000E-003	6.95000E-003	2.00000E-005	3.20000E-004	3.20000E-004	0.00000E+000	1.03221E+000	1.03221E+000	1.10000E-004	0.00000E+000	1.03489E+000
Pumps	1.09000E-003	4.70000E-003	6.69300E-002	1.10000E-004	1.40000E-004	1.40000E-004	0.00000E+000	9.32593E+000	9.32593E+000	5.10000E-004	0.00000E+000	9.33865E+000
Rubber Tired Dozers	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000
Tractors/Loaders/Backhoes	1.25000E-003	5.43000E-003	7.72900E-002	1.00000E-004	1.70000E-004	1.70000E-004	0.00000E+000	9.00806E+000	9.00806E+000	2.91000E-003	0.00000E+000	9.08090E+000
Welders	3.99500E-002	1.99170E-001	2.26880E-001	3.40000E-004	9.78000E-003	9.78000E-003	0.00000E+000	2.48451E+001	2.48451E+001	3.24000E-003	0.00000E+000	2.49260E+001

Equipment Type	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Percent Reduction												
Aerial Lifts	-1.14754E-001	-5.71574E-001	-1.64903E-001	0.00000E+000	7.36842E-001	7.05882E-001	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	4.09900E-006
Air Compressors	8.63071E-001	9.15476E-001	-8.50425E-003	0.00000E+000	9.61538E-001	9.61538E-001	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	3.55442E-006
Concrete/Industrial Saws	8.37795E-001	9.10832E-001	-5.03134E-002	0.00000E+000	9.51049E-001	9.51049E-001	0.00000E+000	1.12723E-006	1.12723E-006	0.00000E+000	0.00000E+000	1.12559E-006
Cranes	9.07920E-001	9.54641E-001	8.98160E-002	0.00000E+000	9.80161E-001	9.78437E-001	0.00000E+000	1.15823E-006	1.15823E-006	0.00000E+000	0.00000E+000	1.14894E-006
Forklifts	8.54037E-001	9.30788E-001	5.50775E-003	0.00000E+000	9.71154E-001	9.68750E-001	0.00000E+000	2.99372E-006	2.99372E-006	0.00000E+000	0.00000E+000	2.96970E-006
Generator Sets	8.16024E-001	9.09987E-001	-1.00868E-001	0.00000E+000	9.47606E-001	9.47606E-001	0.00000E+000	1.07228E-006	1.07228E-006	0.00000E+000	0.00000E+000	1.07091E-006
Plate Compactors	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000
Pumps	8.26433E-001	9.11271E-001	-8.44135E-002	0.00000E+000	9.52218E-001	9.52218E-001	0.00000E+000	1.07228E-006	1.07228E-006	0.00000E+000	0.00000E+000	1.07082E-006
Rubber Tired Dozers	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000
Tractors/Loaders/Backhoes	7.97735E-001	9.13203E-001	-3.61979E-002	0.00000E+000	9.53930E-001	9.49853E-001	0.00000E+000	1.11012E-006	1.11012E-006	0.00000E+000	0.00000E+000	1.10121E-006
Welders	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	1.20748E-006	1.20748E-006	0.00000E+000	0.00000E+000	1.20356E-006

Fugitive Dust Mitigation

Yes/No	Mitigation Measure	Mitigation Input		Mitigation Input		Mitigation Input	
No	Soil Stabilizer for unpaved Roads	PM10 Reduction	0.00	PM2.5 Reduction	0.00		
No	Replace Ground Cover of Area Disturbed	PM10 Reduction	0.00	PM2.5 Reduction	0.00		
Yes	Water Exposed Area	PM10 Reduction	61.00	PM2.5 Reduction	61.00	Frequency (per day)	3.00
No	Unpaved Road Mitigation	Moisture Content %	0.00	Vehicle Speed (mph)	0.00		
No	Clean Paved Road	% PM Reduction	0.00				

		Unmitigated		Mitigated		Percent Reduction	
Phase	Source	PM10	PM2.5	PM10	PM2.5	PM10	PM2.5
Grading	Fugitive Dust	0.00	0.00	0.00	0.00	0.58	0.00
Grading	Roads	0.06	0.02	0.06	0.02	0.00	0.00

Operational Percent Reduction Summary

Category	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Percent Reduction												
Architectural Coating	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Consumer Products	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hearth	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Landscaping	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mobile	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Indoor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Outdoor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Operational Mobile Mitigation

Project Setting:

Mitigation	Category	Measure	% Reduction	Input Value 1	Input Value 2	Input Value
No	Land Use	Increase Density	0.00			
No	Land Use	Increase Diversity	-0.01	0.13		

No	Land Use	Improve Walkability Design	0.00			
No	Land Use	Improve Destination Accessibility	0.00			
No	Land Use	Increase Transit Accessibility	0.25			
No	Land Use	Integrate Below Market Rate Housing	0.00			
	Land Use	Land Use SubTotal	0.00			
No	Neighborhood Enhancements	Improve Pedestrian Network				
No	Neighborhood Enhancements	Provide Traffic Calming Measures				
No	Neighborhood Enhancements	Implement NEV Network	0.00			
	Neighborhood Enhancements	Neighborhood Enhancements Subtotal	0.00			
No	Parking Policy Pricing	Limit Parking Supply	0.00			
No	Parking Policy Pricing	Unbundle Parking Costs	0.00			
No	Parking Policy Pricing	On-street Market Pricing	0.00			
	Parking Policy Pricing	Parking Policy Pricing Subtotal	0.00			
No	Transit Improvements	Provide BRT System	0.00			
No	Transit Improvements	Expand Transit Network	0.00			
No	Transit Improvements	Increase Transit Frequency	0.00			
	Transit Improvements	Transit Improvements Subtotal	0.00			
		Land Use and Site Enhancement Subtotal	0.00			
No	Commute	Implement Trip Reduction Program				
No	Commute	Transit Subsidy				
No	Commute	Implement Employee Parking "Cash Out"				
No	Commute	Workplace Parking Charge				

No	Commute	Encourage Telecommuting and Alternative Work Schedules	0.00				
No	Commute	Market Commute Trip Reduction Option	0.00				
No	Commute	Employee Vanpool/Shuttle	0.00			2.00	
No	Commute	Provide Ride Sharing Program					
	Commute	Commute Subtotal	0.00				
No	School Trip	Implement School Bus Program	0.00				
		Total VMT Reduction	0.00				

Area Mitigation

Measure Implemented	Mitigation Measure	Input Value
No	Only Natural Gas Hearth	
No	No Hearth	
No	Use Low VOC Cleaning Supplies	
No	Use Low VOC Paint (Residential Interior)	50.00
No	Use Low VOC Paint (Residential Exterior)	50.00
No	Use Low VOC Paint (Non-residential Interior)	100.00
No	Use Low VOC Paint (Non-residential Exterior)	100.00
No	Use Low VOC Paint (Parking)	100.00
No	% Electric Lawnmower	
No	% Electric Leafblower	
No	% Electric Chainsaw	

Energy Mitigation Measures

Measure Implemented	Mitigation Measure	Input Value 1	Input Value 2
No	Exceed Title 24		
No	Install High Efficiency Lighting		
No	On-site Renewable		

Appliance Type	Land Use Subtype	% Improvement
ClothWasher		30.00
DishWasher		15.00
Fan		50.00
Refrigerator		15.00

Water Mitigation Measures

Measure Implemented	Mitigation Measure	Input Value 1	Input Value 2
No	Apply Water Conservation on Strategy		
No	Use Reclaimed Water		
No	Use Grey Water		
No	Install low-flow bathroom faucet	32.00	
No	Install low-flow Kitchen faucet	18.00	
No	Install low-flow Toilet	20.00	
No	Install low-flow Shower	20.00	
No	Turf Reduction		
No	Use Water Efficient Irrigation Systems	6.10	
No	Water Efficient Landscape		

Solid Waste Mitigation

Mitigation Measures	Input Value
Institute Recycling and Composting Services Percent Reduction in Waste Disposed	

SCR-FCCU

Los Angeles-South Coast County, Annual

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
Industrial Park	3.01	1000sqft	0.07	3,014.00	0

1.2 Other Project Characteristics

Urbanization	Urban	**Wind Speed (m/s)**	2.2	**Precipitation Freq (Days)**	33
Climate Zone	11			**Operational Year**	2021
Utility Company	Los Angeles Department of Water & Power				
CO2 Intensity (lb/MWhr)	1227.89	**CH4 Intensity (lb/MWhr)**	0.029	**N2O Intensity (lb/MWhr)**	0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics - Some facilities use SCE while others use LADWP, model here uses LADWP to generate conservative GHG values.

Land Use - Lot Acreage based on 2015 NOX RECLAIM ANALYSIS: one SCR for FCCU with a plot of 2475 sq.ft + one 11,000-gallon ammonia tank with a plot of 539 sq.ft.

Construction Phase - 015 NOx RECLAIM assumed 12 months (260 days) of construction duration.

Off-road Equipment - Equipment from 2015 NOX RECLAIM EA's Appendix E-2, added an off-highway truck to represent water truck.

Trips and VMT - Based on 2015 NOx RECLAIM EA's Appendix E-2, assume 1 haul truck because the EA assumed 1 ton/day of material trucked away.

Construction Off-road Equipment Mitigation - Tier 4 final for all equipment that is 50hp or greater.

Off-road Equipment - Equipment list per 2015 NOx RECLAIM EA's Appendix E-2, added 1 off-highway truck to represent water truck, added Rubber Tired Dozer of 0 usage only to enable entry on next page.

Grading - Assume 3 ft cut of the 3,014 sq.ft plots (SCR +ammonia tank), and assume all cut material will be exported offsite

Energy Use -

SCR-FCCU - Los Angeles-South Coast County, Annual

Table Name	Column Name	Default Value	New Value
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	2.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	2.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	2.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	3.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstructionPhase	NumDays	2.00	260.00
tblConstructionPhase	PhaseEndDate	6/8/2021	6/2/2022
tblGrading	AcresOfGrading	0.00	0.07
tblGrading	MaterialExported	0.00	334.89
tblOffRoadEquipment	HorsePower	231.00	120.00

tblOffRoadEquipment	LoadFactor	0.31	0.31
tblOffRoadEquipment	LoadFactor	0.38	0.38
tblOffRoadEquipment	LoadFactor	0.37	0.37
tblOffRoadEquipment	OffRoadEquipmentType		Aerial Lifts
tblOffRoadEquipment	OffRoadEquipmentType		Air Compressors
tblOffRoadEquipment	OffRoadEquipmentType		Generator Sets
tblOffRoadEquipment	OffRoadEquipmentType		Off-Highway Trucks
tblOffRoadEquipment	OffRoadEquipmentType		Plate Compactors
tblOffRoadEquipment	OffRoadEquipmentType		Pumps
tblOffRoadEquipment	OffRoadEquipmentType		Tractors/Loaders/Backhoes
tblOffRoadEquipment	OffRoadEquipmentType		Welders
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	UsageHours	8.00	2.00
tblOffRoadEquipment	UsageHours	1.00	0.00
tblOffRoadEquipment	UsageHours	6.00	8.00
tblTripsAndVMT	HaulingTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripLength	6.90	50.00
tblTripsAndVMT	VendorTripNumber	0.00	4.00
tblTripsAndVMT	WorkerTripLength	14.70	25.00
tblTripsAndVMT	WorkerTripNumber	53.00	280.00

2.0 Emissions Summary

2.1 Overall Construction

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2021	0.4493	2.5446	3.5551	8.2300e-003	0.4049	0.1247	0.5296	0.1078	0.1203	0.2281	0.0000	720.1065	720.1065	0.0684	0.0000	721.8169
2022	0.3002	1.6820	2.4870	5.8800e-003	0.2943	0.0782	0.3725	0.0784	0.0754	0.1538	0.0000	514.0737	514.0737	0.0481	0.0000	515.2767
Maximum	**0.4493**	**2.5446**	**3.5551**	**8.2300e-003**	**0.4049**	**0.1247**	**0.5296**	**0.1078**	**0.1203**	**0.2281**	**0.0000**	**720.1065**	**720.1065**	**0.0684**	**0.0000**	**721.8169**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2021	0.2921	0.9662	3.7293	8.2300e-003	0.4049	0.0358	0.4407	0.1078	0.0356	0.1434	0.0000	720.1061	720.1061	0.0684	0.0000	721.8165
2022	0.1989	0.6755	2.6299	5.8800e-003	0.2942	0.0232	0.3174	0.0784	0.0230	0.1013	0.0000	514.0734	514.0734	0.0481	0.0000	515.2765
Maximum	**0.2921**	**0.9662**	**3.7293**	**8.2300e-003**	**0.4049**	**0.0358**	**0.4407**	**0.1078**	**0.0356**	**0.1434**	**0.0000**	**720.1061**	**720.1061**	**0.0684**	**0.0000**	**721.8165**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**34.50**	**61.16**	**-5.25**	**0.00**	**0.01**	**70.92**	**15.96**	**0.00**	**70.08**	**35.91**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

SCR-FCCU - Los Angeles-South Coast County, Annual

Quarter	Start Date	End Date	Maximum Unmitigated ROG + NOX (tons/quarter)	Maximum Mitigated ROG + NOX (tons/quarter)
1	6-7-2021	9-6-2021	1.3023	0.5419
2	9-7-2021	12-6-2021	1.2985	0.5463
3	12-7-2021	3-6-2022	1.2054	0.5269
4	3-7-2022	6-6-2022	1.1385	0.4997
		Highest	1.3023	0.5463

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	0.0123	0.0000	4.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	7.0000e-005	7.0000e-005	0.0000	0.0000	8.0000e-005
Energy	1.7000e-004	1.5400e-003	1.2900e-003	1.0000e-005		1.2000e-004	1.2000e-004		1.2000e-004	1.2000e-004	0.0000	23.4804	23.4804	5.5000e-004	1.4000e-004	23.5350
Mobile	5.8100e-003	0.0308	0.0852	3.0000e-004	0.0243	2.5000e-004	0.0245	6.5000e-003	2.4000e-004	6.7400e-003	0.0000	27.6222	27.6222	1.4500e-003	0.0000	27.6586
Waste						0.0000	0.0000		0.0000	0.0000	0.7572	0.0000	0.7572	0.0448	0.0000	1.8758
Water						0.0000	0.0000		0.0000	0.0000	0.2208	5.0480	5.2688	0.0228	5.6000e-004	6.0058
Total	**0.0183**	**0.0323**	**0.0865**	**3.1000e-004**	**0.0243**	**3.7000e-004**	**0.0246**	**6.5000e-003**	**3.6000e-004**	**6.8600e-003**	**0.9780**	**56.1507**	**57.1287**	**0.0696**	**7.0000e-004**	**59.0752**

2.2 Overall Operational

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	0.0123	0.0000	4.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	7.0000e-005	7.0000e-005	0.0000	0.0000	8.0000e-005
Energy	1.7000e-004	1.5400e-003	1.2900e-003	1.0000e-005		1.2000e-004	1.2000e-004		1.2000e-004	1.2000e-004	0.0000	23.4804	23.4804	5.5000e-004	1.4000e-004	23.5350
Mobile	5.8100e-003	0.0308	0.0852	3.0000e-004	0.0243	2.5000e-004	0.0245	6.5000e-003	2.4000e-004	6.7400e-003	0.0000	27.6222	27.6222	1.4500e-003	0.0000	27.6586
Waste						0.0000	0.0000		0.0000	0.0000	0.7572	0.0000	0.7572	0.0448	0.0000	1.8758
Water						0.0000	0.0000		0.0000	0.0000	0.2208	5.0480	5.2688	0.0228	5.6000e-004	6.0058
Total	**0.0183**	**0.0323**	**0.0865**	**3.1000e-004**	**0.0243**	**3.7000e-004**	**0.0246**	**6.5000e-003**	**3.6000e-004**	**6.8600e-003**	**0.9780**	**56.1507**	**57.1287**	**0.0696**	**7.0000e-004**	**59.0752**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Build SCR and ammonia tank for FCCU	Grading	6/7/2021	6/2/2022	5	260	

Acres of Grading (Site Preparation Phase): 0

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0; Striped Parking Area: 0 (Architectural Coating – sqft)

<u>OffRoad Equipment</u>

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Build SCR and ammonia tank for FCCU	Concrete/Industrial Saws	1	2.00	81	0.73
Build SCR and ammonia tank for FCCU	Rubber Tired Dozers	1	0.00	247	0.40
Build SCR and ammonia tank for FCCU	Aerial Lifts	2	2.00	63	0.31
Build SCR and ammonia tank for FCCU	Cranes	1	8.00	120	0.29
Build SCR and ammonia tank for FCCU	Cranes	1	8.00	231	0.29
Build SCR and ammonia tank for FCCU	Forklifts	1	6.00	89	0.20
Build SCR and ammonia tank for FCCU	Air Compressors	1	8.00	78	0.48
Build SCR and ammonia tank for FCCU	Generator Sets	2	8.00	84	0.74
Build SCR and ammonia tank for FCCU	Off-Highway Trucks	3	1.00	402	0.38
Build SCR and ammonia tank for FCCU	Plate Compactors	1	2.00	8	0.43
Build SCR and ammonia tank for FCCU	Pumps	1	2.00	84	0.74
Build SCR and ammonia tank for FCCU	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Build SCR and ammonia tank for FCCU	Welders	5	8.00	46	0.45

<u>Trips and VMT</u>

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Build SCR and ammonia tank for FCC	21	280.00	4.00	2.00	25.00	50.00	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Use Cleaner Engines for Construction Equipment

Water Exposed Area

3.2 Build SCR and ammonia tank for FCCU - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					6.0000e-005	0.0000	6.0000e-005	1.0000e-005	0.0000	1.0000e-005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	0.3048	2.3219	2.2350	3.9000e-003		0.1212	0.1212		0.1170	0.1170	0.0000	326.0280	326.0280	0.0566	0.0000	327.4418
Total	**0.3048**	**2.3219**	**2.2350**	**3.9000e-003**	**6.0000e-005**	**0.1212**	**0.1212**	**1.0000e-005**	**0.1170**	**0.1170**	**0.0000**	**326.0280**	**326.0280**	**0.0566**	**0.0000**	**327.4418**

3.2 Build SCR and ammonia tank for FCCU - 2021

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	1.6000e-004	4.0000e-005	0.0000	2.0000e-005	0.0000	2.0000e-005	0.0000	0.0000	0.0000	0.0000	0.0440	0.0440	0.0000	0.0000	0.0441
Vendor	4.1400e-003	0.1070	0.0306	4.5000e-004	0.0136	4.0000e-004	0.0140	3.9300e-003	3.8000e-004	4.3100e-003	0.0000	43.8088	43.8088	1.7500e-003	0.0000	43.8527
Worker	0.1404	0.1156	1.2894	3.8700e-003	0.3912	3.1300e-003	0.3943	0.1039	2.8800e-003	0.1068	0.0000	350.2257	350.2257	0.0101	0.0000	350.4783
Total	**0.1445**	**0.2227**	**1.3201**	**4.3200e-003**	**0.4049**	**3.5300e-003**	**0.4084**	**0.1078**	**3.2600e-003**	**0.1111**	**0.0000**	**394.0785**	**394.0785**	**0.0119**	**0.0000**	**394.3750**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					2.0000e-005	0.0000	2.0000e-005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	0.1476	0.7435	2.4092	3.9000e-003		0.0323	0.0323		0.0323	0.0323	0.0000	326.0276	326.0276	0.0566	0.0000	327.4415
Total	**0.1476**	**0.7435**	**2.4092**	**3.9000e-003**	**2.0000e-005**	**0.0323**	**0.0323**	**0.0000**	**0.0323**	**0.0323**	**0.0000**	**326.0276**	**326.0276**	**0.0566**	**0.0000**	**327.4415**

3.2 Build SCR and ammonia tank for FCCU - 2021

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	1.6000e-004	4.0000e-005	0.0000	2.0000e-005	0.0000	2.0000e-005	0.0000	0.0000	0.0000	0.0000	0.0440	0.0440	0.0000	0.0000	0.0441
Vendor	4.1400e-003	0.1070	0.0306	4.5000e-004	0.0136	4.0000e-004	0.0140	3.9300e-003	3.8000e-004	4.3100e-003	0.0000	43.8088	43.8088	1.7500e-003	0.0000	43.8527
Worker	0.1404	0.1156	1.2894	3.8700e-003	0.3912	3.1300e-003	0.3943	0.1039	2.8800e-003	0.1068	0.0000	350.2257	350.2257	0.0101	0.0000	350.4783
Total	**0.1445**	**0.2227**	**1.3201**	**4.3200e-003**	**0.4049**	**3.5300e-003**	**0.4084**	**0.1078**	**3.2600e-003**	**0.1111**	**0.0000**	**394.0785**	**394.0785**	**0.0119**	**0.0000**	**394.3750**

3.2 Build SCR and ammonia tank for FCCU - 2022

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					6.0000e-005	0.0000	6.0000e-005	1.0000e-005	0.0000	1.0000e-005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	0.2015	1.5342	1.6015	2.8400e-003		0.0757	0.0757		0.0732	0.0732	0.0000	236.9467	236.9467	0.0402	0.0000	237.9525
Total	**0.2015**	**1.5342**	**1.6015**	**2.8400e-003**	**6.0000e-005**	**0.0757**	**0.0758**	**1.0000e-005**	**0.0732**	**0.0732**	**0.0000**	**236.9467**	**236.9467**	**0.0402**	**0.0000**	**237.9525**

3.2 Build SCR and ammonia tank for FCCU - 2022

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	1.1000e-004	3.0000e-005	0.0000	1.0000e-005	0.0000	2.0000e-005	0.0000	0.0000	0.0000	0.0000	0.0316	0.0316	0.0000	0.0000	0.0316
Vendor	2.8500e-003	0.0718	0.0213	3.3000e-004	9.9200e-003	2.5000e-004	0.0102	2.8600e-003	2.4000e-004	3.1000e-003	0.0000	31.5483	31.5483	1.2600e-003	0.0000	31.5797
Worker	0.0958	0.0759	0.8641	2.7200e-003	0.2843	2.2000e-003	0.2865	0.0755	2.0300e-003	0.0775	0.0000	245.5471	245.5471	6.6300e-003	0.0000	245.7129
Total	**0.0987**	**0.1478**	**0.8855**	**3.0500e-003**	**0.2942**	**2.4500e-003**	**0.2967**	**0.0784**	**2.2700e-003**	**0.0806**	**0.0000**	**277.1270**	**277.1270**	**7.8900e-003**	**0.0000**	**277.3243**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					2.0000e-005	0.0000	2.0000e-005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	0.1002	0.5277	1.7444	2.8400e-003		0.0207	0.0207		0.0207	0.0207	0.0000	236.9464	236.9464	0.0402	0.0000	237.9522
Total	**0.1002**	**0.5277**	**1.7444**	**2.8400e-003**	**2.0000e-005**	**0.0207**	**0.0207**	**0.0000**	**0.0207**	**0.0207**	**0.0000**	**236.9464**	**236.9464**	**0.0402**	**0.0000**	**237.9522**

3.2 Build SCR and ammonia tank for FCCU - 2022

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	1.1000e-004	3.0000e-005	0.0000	1.0000e-005	0.0000	2.0000e-005	0.0000	0.0000	0.0000	0.0000	0.0316	0.0316	0.0000	0.0000	0.0316
Vendor	2.8500e-003	0.0718	0.0213	3.3000e-004	9.9200e-003	2.5000e-004	0.0102	2.8600e-003	2.4000e-004	3.1000e-003	0.0000	31.5483	31.5483	1.2600e-003	0.0000	31.5797
Worker	0.0958	0.0759	0.8641	2.7200e-003	0.2843	2.2000e-003	0.2865	0.0755	2.0300e-003	0.0775	0.0000	245.5471	245.5471	6.6300e-003	0.0000	245.7129
Total	**0.0987**	**0.1478**	**0.8855**	**3.0500e-003**	**0.2942**	**2.4500e-003**	**0.2967**	**0.0784**	**2.2700e-003**	**0.0806**	**0.0000**	**277.1270**	**277.1270**	**7.8900e-003**	**0.0000**	**277.3243**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

Category	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	tons/yr										MT/yr					
Mitigated	5.8100e-003	0.0308	0.0852	3.0000e-004	0.0243	2.5000e-004	0.0245	6.5000e-003	2.4000e-004	6.7400e-003	0.0000	27.6222	27.6222	1.4500e-003	0.0000	27.6586
Unmitigated	5.8100e-003	0.0308	0.0852	3.0000e-004	0.0243	2.5000e-004	0.0245	6.5000e-003	2.4000e-004	6.7400e-003	0.0000	27.6222	27.6222	1.4500e-003	0.0000	27.6586

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
Industrial Park	20.56	7.49	2.20	63,905	63,905
Total	20.56	7.49	2.20	63,905	63,905

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
Industrial Park	16.60	8.40	6.90	59.00	28.00	13.00	79	19	2

4.4 Fleet Mix

Land Use	LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
Industrial Park	0.547192	0.045177	0.202743	0.121510	0.016147	0.006143	0.019743	0.029945	0.002479	0.002270	0.005078	0.000682	0.000891

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Electricity Mitigated						0.0000	0.0000		0.0000	0.0000	0.0000	21.8061	21.8061	5.2000e-004	1.1000e-004	21.8507
Electricity Unmitigated						0.0000	0.0000		0.0000	0.0000	0.0000	21.8061	21.8061	5.2000e-004	1.1000e-004	21.8507
NaturalGas Mitigated	1.7000e-004	1.5400e-003	1.2900e-003	1.0000e-005		1.2000e-004	1.2000e-004		1.2000e-004	1.2000e-004	0.0000	1.6743	1.6743	3.0000e-005	3.0000e-005	1.6843
NaturalGas Unmitigated	1.7000e-004	1.5400e-003	1.2900e-003	1.0000e-005		1.2000e-004	1.2000e-004		1.2000e-004	1.2000e-004	0.0000	1.6743	1.6743	3.0000e-005	3.0000e-005	1.6843

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	tons/yr										MT/yr					
Industrial Park	31375.7	1.7000e-004	1.5400e-003	1.2900e-003	1.0000e-005		1.2000e-004	1.2000e-004		1.2000e-004	1.2000e-004	0.0000	1.6743	1.6743	3.0000e-005	3.0000e-005	1.6843
Total		**1.7000e-004**	**1.5400e-003**	**1.2900e-003**	**1.0000e-005**		**1.2000e-004**	**1.2000e-004**		**1.2000e-004**	**1.2000e-004**	**0.0000**	**1.6743**	**1.6743**	**3.0000e-005**	**3.0000e-005**	**1.6843**

5.2 Energy by Land Use - NaturalGas

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	tons/yr										MT/yr					
Industrial Park	31375.7	1.7000e-004	1.5400e-003	1.2900e-003	1.0000e-005		1.2000e-004	1.2000e-004		1.2000e-004	1.2000e-004	0.0000	1.6743	1.6743	3.0000e-005	3.0000e-005	1.6843
Total		**1.7000e-004**	**1.5400e-003**	**1.2900e-003**	**1.0000e-005**		**1.2000e-004**	**1.2000e-004**		**1.2000e-004**	**1.2000e-004**	**0.0000**	**1.6743**	**1.6743**	**3.0000e-005**	**3.0000e-005**	**1.6843**

5.3 Energy by Land Use - Electricity

Unmitigated

	Electricity Use	Total CO2	CH4	N2O	CO2e
Land Use	kWh/yr	MT/yr			
Industrial Park	39151.9	21.8061	5.2000e-004	1.1000e-004	21.8507
Total		**21.8061**	**5.2000e-004**	**1.1000e-004**	**21.8507**

5.3 Energy by Land Use - Electricity

Mitigated

	Electricity Use	Total CO2	CH4	N2O	CO2e
Land Use	kWh/yr	MT/yr			
Industrial Park	39151.9	21.8061	5.2000e-004	1.1000e-004	21.8507
Total		**21.8061**	**5.2000e-004**	**1.1000e-004**	**21.8507**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Mitigated	0.0123	0.0000	4.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	7.0000e-005	7.0000e-005	0.0000	0.0000	8.0000e-005
Unmitigated	0.0123	0.0000	4.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	7.0000e-005	7.0000e-005	0.0000	0.0000	8.0000e-005

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	tons/yr										MT/yr					
Architectural Coating	1.4000e-003					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Consumer Products	0.0109					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Landscaping	0.0000	0.0000	4.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	7.0000e-005	7.0000e-005	0.0000	0.0000	8.0000e-005
Total	**0.0123**	**0.0000**	**4.0000e-005**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**7.0000e-005**	**7.0000e-005**	**0.0000**	**0.0000**	**8.0000e-005**

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	tons/yr										MT/yr					
Architectural Coating	1.4000e-003					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Consumer Products	0.0109					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Landscaping	0.0000	0.0000	4.0000e-005	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	7.0000e-005	7.0000e-005	0.0000	0.0000	8.0000e-005
Total	**0.0123**	**0.0000**	**4.0000e-005**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**7.0000e-005**	**7.0000e-005**	**0.0000**	**0.0000**	**8.0000e-005**

7.0 Water Detail

7.1 Mitigation Measures Water

	Total CO2	CH4	N2O	CO2e
Category	MT/yr			
Mitigated	5.2688	0.0228	5.6000e-004	6.0058
Unmitigated	5.2688	0.0228	5.6000e-004	6.0058

7.2 Water by Land Use

Unmitigated

	Indoor/Outdoor Use	Total CO2	CH4	N2O	CO2e
Land Use	Mgal	MT/yr			
Industrial Park	0.696063 / 0	5.2688	0.0228	5.6000e-004	6.0058
Total		**5.2688**	**0.0228**	**5.6000e-004**	**6.0058**

7.2 Water by Land Use

Mitigated

	Indoor/Outdoor Use	Total CO2	CH4	N2O	CO2e
Land Use	Mgal	MT/yr			
Industrial Park	0.696063 / 0	5.2688	0.0228	5.6000e-004	6.0058
Total		**5.2688**	**0.0228**	**5.6000e-004**	**6.0058**

8.0 Waste Detail

8.1 Mitigation Measures Waste

Category/Year

	Total CO2	CH4	N2O	CO2e
	MT/yr			
Mitigated	0.7572	0.0448	0.0000	1.8758
Unmitigated	0.7572	0.0448	0.0000	1.8758

8.2 Waste by Land Use

Unmitigated

	Waste Disposed	Total CO2	CH4	N2O	CO2e
Land Use	tons	MT/yr			
Industrial Park	3.73	0.7572	0.0448	0.0000	1.8758
Total		**0.7572**	**0.0448**	**0.0000**	**1.8758**

Mitigated

	Waste Disposed	Total CO2	CH4	N2O	CO2e
Land Use	tons	MT/yr			
Industrial Park	3.73	0.7572	0.0448	0.0000	1.8758
Total		**0.7572**	**0.0448**	**0.0000**	**1.8758**

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Stationary Equipment

Fire Pumps and Emergency Generators

Equipment Type	Number	Hours/Day	Hours/Year	Horse Power	Load Factor	Fuel Type

Boilers

Equipment Type	Number	Heat Input/Day	Heat Input/Year	Boiler Rating	Fuel Type

User Defined Equipment

Equipment Type	Number

11.0 Vegetation

SCR-FCCU

Los Angeles-South Coast County, Summer

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
Industrial Park	3.01	1000sqft	0.07	3,014.00	0

1.2 Other Project Characteristics

Urbanization	Urban	**Wind Speed (m/s)**	2.2	**Precipitation Freq (Days)**	33
Climate Zone	11			**Operational Year**	2021
Utility Company	Los Angeles Department of Water & Power				
CO2 Intensity (lb/MWhr)	1227.89	**CH4 Intensity (lb/MWhr)**	0.029	**N2O Intensity (lb/MWhr)**	0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics - Some facilities use SCE while others use LADWP, model here uses LADWP to generate conservative GHG values.

Land Use - Lot Acreage based on 2015 NOX RECLAIM ANALYSIS: one SCR for FCCU with a plot of 2475 sq.ft + one 11,000-gallon ammonia tank with a plot of 539 sq.ft.

Construction Phase - 015 NOx RECLAIM assumed 12 months (260 days) of construction duration.

Off-road Equipment - Equipment from 2015 NOX RECLAIM EA's Appendix E-2, added an off-highway truck to represent water truck.

Trips and VMT - Based on 2015 NOx RECLAIM EA's Appendix E-2, assume 1 haul truck because the EA assumed 1 ton/day of material trucked away.

Construction Off-road Equipment Mitigation - Tier 4 final for all equipment that is 50hp or greater.

Off-road Equipment - Equipment list per 2015 NOx RECLAIM EA's Appendix E-2, added 1 off-highway truck to represent water truck, added Rubber Tired Dozer of 0 usage only to enable entry on next page.

Grading - Assume 3 ft cut of the 3,014 sq.ft plots (SCR +ammonia tank), and assume all cut material will be exported offsite

Energy Use -

SCR-FCCU - Los Angeles-South Coast County, Summer

Table Name	Column Name	Default Value	New Value
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	2.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	2.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	2.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	3.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstructionPhase	NumDays	2.00	260.00
tblConstructionPhase	PhaseEndDate	6/8/2021	6/2/2022
tblGrading	AcresOfGrading	0.00	0.07
tblGrading	MaterialExported	0.00	334.89
tblOffRoadEquipment	HorsePower	231.00	120.00

tblOffRoadEquipment	LoadFactor	0.31	0.31
tblOffRoadEquipment	LoadFactor	0.38	0.38
tblOffRoadEquipment	LoadFactor	0.37	0.37
tblOffRoadEquipment	OffRoadEquipmentType		Aerial Lifts
tblOffRoadEquipment	OffRoadEquipmentType		Air Compressors
tblOffRoadEquipment	OffRoadEquipmentType		Generator Sets
tblOffRoadEquipment	OffRoadEquipmentType		Off-Highway Trucks
tblOffRoadEquipment	OffRoadEquipmentType		Plate Compactors
tblOffRoadEquipment	OffRoadEquipmentType		Pumps
tblOffRoadEquipment	OffRoadEquipmentType		Tractors/Loaders/Backhoes
tblOffRoadEquipment	OffRoadEquipmentType		Welders
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	UsageHours	8.00	2.00
tblOffRoadEquipment	UsageHours	1.00	0.00
tblOffRoadEquipment	UsageHours	6.00	8.00
tblTripsAndVMT	HaulingTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripLength	6.90	50.00
tblTripsAndVMT	VendorTripNumber	0.00	4.00
tblTripsAndVMT	WorkerTripLength	14.70	25.00
tblTripsAndVMT	WorkerTripNumber	53.00	280.00

2.0 Emissions Summary

2.1 Overall Construction (Maximum Daily Emission)

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2021	5.9593	33.6770	48.6804	0.1121	5.5063	1.6625	7.1688	1.4641	1.6035	3.0676	0.0000	10,816.1662	10,816.1662	1.0128	0.0000	10,841.4871
2022	5.4763	30.6342	46.8317	0.1101	5.5064	1.4346	6.9409	1.4641	1.3841	2.8482	0.0000	10,621.7535	10,621.7535	0.9800	0.0000	10,646.2537
Maximum	**5.9593**	**33.6770**	**48.6804**	**0.1121**	**5.5064**	**1.6625**	**7.1688**	**1.4641**	**1.6035**	**3.0676**	**0.0000**	**10,816.1662**	**10,816.1662**	**1.0128**	**0.0000**	**10,841.4871**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2021	3.8625	12.6314	51.0029	0.1121	5.5060	0.4779	5.9840	1.4641	0.4744	1.9385	0.0000	10,816.1662	10,816.1662	1.0128	0.0000	10,841.4871
2022	3.6167	12.1673	49.4547	0.1101	5.5061	0.4249	5.9310	1.4641	0.4215	1.8856	0.0000	10,621.7535	10,621.7535	0.9800	0.0000	10,646.2537
Maximum	**3.8625**	**12.6314**	**51.0029**	**0.1121**	**5.5061**	**0.4779**	**5.9840**	**1.4641**	**0.4744**	**1.9385**	**0.0000**	**10,816.1662**	**10,816.1662**	**1.0128**	**0.0000**	**10,841.4871**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**34.60**	**61.44**	**-5.18**	**0.00**	**0.00**	**70.85**	**15.56**	**0.00**	**70.01**	**35.36**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	0.0674	0.0000	3.1000e-004	0.0000		0.0000	0.0000		0.0000	0.0000		6.6000e-004	6.6000e-004	0.0000		7.0000e-004
Energy	9.3000e-004	8.4300e-003	7.0800e-003	5.0000e-005		6.4000e-004	6.4000e-004		6.4000e-004	6.4000e-004		10.1131	10.1131	1.9000e-004	1.9000e-004	10.1732
Mobile	0.0429	0.2064	0.6246	2.1800e-003	0.1739	1.7900e-003	0.1756	0.0465	1.6700e-003	0.0482		221.8055	221.8055	0.0114		222.0898
Total	**0.1112**	**0.2148**	**0.6320**	**2.2300e-003**	**0.1739**	**2.4300e-003**	**0.1763**	**0.0465**	**2.3100e-003**	**0.0488**		**231.9192**	**231.9192**	**0.0116**	**1.9000e-004**	**232.2637**

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	0.0674	0.0000	3.1000e-004	0.0000		0.0000	0.0000		0.0000	0.0000		6.6000e-004	6.6000e-004	0.0000		7.0000e-004
Energy	9.3000e-004	8.4300e-003	7.0800e-003	5.0000e-005		6.4000e-004	6.4000e-004		6.4000e-004	6.4000e-004		10.1131	10.1131	1.9000e-004	1.9000e-004	10.1732
Mobile	0.0429	0.2064	0.6246	2.1800e-003	0.1739	1.7900e-003	0.1756	0.0465	1.6700e-003	0.0482		221.8055	221.8055	0.0114		222.0898
Total	**0.1112**	**0.2148**	**0.6320**	**2.2300e-003**	**0.1739**	**2.4300e-003**	**0.1763**	**0.0465**	**2.3100e-003**	**0.0488**		**231.9192**	**231.9192**	**0.0116**	**1.9000e-004**	**232.2637**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Build SCR and ammonia tank for FCCU	Grading	6/7/2021	6/2/2022	5	260	

Acres of Grading (Site Preparation Phase): 0

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0; Striped Parking Area: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Build SCR and ammonia tank for FCCU	Concrete/Industrial Saws	1	2.00	81	0.73
Build SCR and ammonia tank for FCCU	Rubber Tired Dozers	1	0.00	247	0.40
Build SCR and ammonia tank for FCCU	Aerial Lifts	2	2.00	63	0.31
Build SCR and ammonia tank for FCCU	Cranes	1	8.00	120	0.29
Build SCR and ammonia tank for FCCU	Cranes	1	8.00	231	0.29
Build SCR and ammonia tank for FCCU	Forklifts	1	6.00	89	0.20
Build SCR and ammonia tank for FCCU	Air Compressors	1	8.00	78	0.48
Build SCR and ammonia tank for FCCU	Generator Sets	2	8.00	84	0.74
Build SCR and ammonia tank for FCCU	Off-Highway Trucks	3	1.00	402	0.38
Build SCR and ammonia tank for FCCU	Plate Compactors	1	2.00	8	0.43
Build SCR and ammonia tank for FCCU	Pumps	1	2.00	84	0.74
Build SCR and ammonia tank for FCCU	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Build SCR and ammonia tank for FCCU	Welders	5	8.00	46	0.45

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Build SCR and ammonia tank for FCC	21	280.00	4.00	2.00	25.00	50.00	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Use Cleaner Engines for Construction Equipment

Water Exposed Area

3.2 Build SCR and ammonia tank for FCCU - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					4.3000e-004	0.0000	4.3000e-004	5.0000e-005	0.0000	5.0000e-005			0.0000			0.0000
Off-Road	4.0645	30.9588	29.8003	0.0520		1.6155	1.6155		1.5600	1.5600		4,791.7909	4,791.7909	0.8312		4,812.5712
Total	**4.0645**	**30.9588**	**29.8003**	**0.0520**	**4.3000e-004**	**1.6155**	**1.6159**	**5.0000e-005**	**1.5600**	**1.5600**		**4,791.7909**	**4,791.7909**	**0.8312**		**4,812.5712**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	6.0000e-005	2.0600e-003	4.8000e-004	1.0000e-005	2.1000e-004	1.0000e-005	2.2000e-004	6.0000e-005	1.0000e-005	6.0000e-005		0.6511	0.6511	4.0000e-005		0.6522
Vendor	0.0548	1.3627	0.4045	6.0400e-003	0.1849	5.2600e-003	0.1902	0.0532	5.0300e-003	0.0582		645.1456	645.1456	0.0256		645.7863
Worker	1.8399	1.3534	18.4751	0.0540	5.3208	0.0418	5.3625	1.4108	0.0385	1.4493		5,378.5786	5,378.5786	0.1560		5,382.4773
Total	**1.8948**	**2.7182**	**18.8801**	**0.0600**	**5.5059**	**0.0470**	**5.5529**	**1.4641**	**0.0435**	**1.5076**		**6,024.3753**	**6,024.3753**	**0.1816**		**6,028.9159**

3.2 Build SCR and ammonia tank for FCCU - 2021

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					1.7000e-004	0.0000	1.7000e-004	2.0000e-005	0.0000	2.0000e-005			0.0000			0.0000
Off-Road	1.9677	9.9132	32.1228	0.0520		0.4309	0.4309		0.4309	0.4309	0.0000	4,791.7909	4,791.7909	0.8312		4,812.5712
Total	**1.9677**	**9.9132**	**32.1228**	**0.0520**	**1.7000e-004**	**0.4309**	**0.4311**	**2.0000e-005**	**0.4309**	**0.4309**	**0.0000**	**4,791.7909**	**4,791.7909**	**0.8312**		**4,812.5712**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	6.0000e-005	2.0600e-003	4.8000e-004	1.0000e-005	2.1000e-004	1.0000e-005	2.2000e-004	6.0000e-005	1.0000e-005	6.0000e-005		0.6511	0.6511	4.0000e-005		0.6522
Vendor	0.0548	1.3627	0.4045	6.0400e-003	0.1849	5.2600e-003	0.1902	0.0532	5.0300e-003	0.0582		645.1456	645.1456	0.0256		645.7863
Worker	1.8399	1.3534	18.4751	0.0540	5.3208	0.0418	5.3625	1.4108	0.0385	1.4493		5,378.5786	5,378.5786	0.1560		5,382.4773
Total	**1.8948**	**2.7182**	**18.8801**	**0.0600**	**5.5059**	**0.0470**	**5.5529**	**1.4641**	**0.0435**	**1.5076**		**6,024.3753**	**6,024.3753**	**0.1816**		**6,028.9159**

3.2 Build SCR and ammonia tank for FCCU - 2022

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					4.3000e-004	0.0000	4.3000e-004	5.0000e-005	0.0000	5.0000e-005			0.0000			0.0000
Off-Road	3.6977	28.1500	29.3849	0.0520		1.3895	1.3895		1.3424	1.3424		4,792.4592	4,792.4592	0.8137		4,812.8016
Total	**3.6977**	**28.1500**	**29.3849**	**0.0520**	**4.3000e-004**	**1.3895**	**1.3899**	**5.0000e-005**	**1.3424**	**1.3425**		**4,792.4592**	**4,792.4592**	**0.8137**		**4,812.8016**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	6.0000e-005	1.9200e-003	4.8000e-004	1.0000e-005	2.8000e-004	1.0000e-005	2.8000e-004	7.0000e-005	1.0000e-005	8.0000e-005		0.6434	0.6434	4.0000e-005		0.6445
Vendor	0.0519	1.2587	0.3880	5.9900e-003	0.1849	4.6200e-003	0.1895	0.0532	4.4200e-003	0.0576		639.3553	639.3553	0.0253		639.9865
Worker	1.7266	1.2236	17.0584	0.0521	5.3208	0.0404	5.3612	1.4108	0.0373	1.4481		5,189.2956	5,189.2956	0.1410		5,192.8210
Total	**1.7786**	**2.4842**	**17.4469**	**0.0581**	**5.5060**	**0.0451**	**5.5510**	**1.4641**	**0.0417**	**1.5058**		**5,829.2943**	**5,829.2943**	**0.1663**		**5,833.4520**

3.2 Build SCR and ammonia tank for FCCU - 2022

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					1.7000e-004	0.0000	1.7000e-004	2.0000e-005	0.0000	2.0000e-005			0.0000			0.0000
Off-Road	1.8381	9.6832	32.0078	0.0520		0.3798	0.3798		0.3798	0.3798	0.0000	4,792.4592	4,792.4592	0.8137		4,812.8016
Total	**1.8381**	**9.6832**	**32.0078**	**0.0520**	**1.7000e-004**	**0.3798**	**0.3800**	**2.0000e-005**	**0.3798**	**0.3798**	**0.0000**	**4,792.4592**	**4,792.4592**	**0.8137**		**4,812.8016**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	6.0000e-005	1.9200e-003	4.8000e-004	1.0000e-005	2.8000e-004	1.0000e-005	2.8000e-004	7.0000e-005	1.0000e-005	8.0000e-005		0.6434	0.6434	4.0000e-005		0.6445
Vendor	0.0519	1.2587	0.3880	5.9900e-003	0.1849	4.6200e-003	0.1895	0.0532	4.4200e-003	0.0576		639.3553	639.3553	0.0253		639.9865
Worker	1.7266	1.2236	17.0584	0.0521	5.3208	0.0404	5.3612	1.4108	0.0373	1.4481		5,189.2956	5,189.2956	0.1410		5,192.8210
Total	**1.7786**	**2.4842**	**17.4469**	**0.0581**	**5.5060**	**0.0451**	**5.5510**	**1.4641**	**0.0417**	**1.5058**		**5,829.2943**	**5,829.2943**	**0.1663**		**5,833.4520**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

Category	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	lb/day										lb/day					
Mitigated	0.0429	0.2064	0.6246	2.1800e-003	0.1739	1.7900e-003	0.1756	0.0465	1.6700e-003	0.0482		221.8055	221.8055	0.0114		222.0898
Unmitigated	0.0429	0.2064	0.6246	2.1800e-003	0.1739	1.7900e-003	0.1756	0.0465	1.6700e-003	0.0482		221.8055	221.8055	0.0114		222.0898

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
Industrial Park	20.56	7.49	2.20	63,905	63,905
Total	20.56	7.49	2.20	63,905	63,905

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
Industrial Park	16.60	8.40	6.90	59.00	28.00	13.00	79	19	2

4.4 Fleet Mix

Land Use	LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
Industrial Park	0.547192	0.045177	0.202743	0.121510	0.016147	0.006143	0.019743	0.029945	0.002479	0.002270	0.005078	0.000682	0.000891

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
NaturalGas Mitigated	9.3000e-004	8.4300e-003	7.0800e-003	5.0000e-005		6.4000e-004	6.4000e-004		6.4000e-004	6.4000e-004		10.1131	10.1131	1.9000e-004	1.9000e-004	10.1732
NaturalGas Unmitigated	9.3000e-004	8.4300e-003	7.0800e-003	5.0000e-005		6.4000e-004	6.4000e-004		6.4000e-004	6.4000e-004		10.1131	10.1131	1.9000e-004	1.9000e-004	10.1732

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
Industrial Park	85.9609	9.3000e-004	8.4300e-003	7.0800e-003	5.0000e-005		6.4000e-004	6.4000e-004		6.4000e-004	6.4000e-004		10.1131	10.1131	1.9000e-004	1.9000e-004	10.1732
Total		**9.3000e-004**	**8.4300e-003**	**7.0800e-003**	**5.0000e-005**		**6.4000e-004**	**6.4000e-004**		**6.4000e-004**	**6.4000e-004**		**10.1131**	**10.1131**	**1.9000e-004**	**1.9000e-004**	**10.1732**

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
Industrial Park	0.0859609	9.3000e-004	8.4300e-003	7.0800e-003	5.0000e-005		6.4000e-004	6.4000e-004		6.4000e-004	6.4000e-004		10.1131	10.1131	1.9000e-004	1.9000e-004	10.1732
Total		**9.3000e-004**	**8.4300e-003**	**7.0800e-003**	**5.0000e-005**		**6.4000e-004**	**6.4000e-004**		**6.4000e-004**	**6.4000e-004**		**10.1131**	**10.1131**	**1.9000e-004**	**1.9000e-004**	**10.1732**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	0.0674	0.0000	3.1000e-004	0.0000		0.0000	0.0000		0.0000	0.0000		6.6000e-004	6.6000e-004	0.0000		7.0000e-004
Unmitigated	0.0674	0.0000	3.1000e-004	0.0000		0.0000	0.0000		0.0000	0.0000		6.6000e-004	6.6000e-004	0.0000		7.0000e-004

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	7.6500e-003					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.0597					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	3.0000e-005	0.0000	3.1000e-004	0.0000		0.0000	0.0000		0.0000	0.0000		6.6000e-004	6.6000e-004	0.0000		7.0000e-004
Total	**0.0674**	**0.0000**	**3.1000e-004**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**6.6000e-004**	**6.6000e-004**	**0.0000**		**7.0000e-004**

6.2 Area by SubCategory

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	7.6500e-003					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.0597					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	3.0000e-005	0.0000	3.1000e-004	0.0000		0.0000	0.0000		0.0000	0.0000		6.6000e-004	6.6000e-004	0.0000		7.0000e-004
Total	**0.0674**	**0.0000**	**3.1000e-004**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**6.6000e-004**	**6.6000e-004**	**0.0000**		**7.0000e-004**

7.0 Water Detail

7.1 Mitigation Measures Water

8.0 Waste Detail

8.1 Mitigation Measures Waste

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Stationary Equipment

Fire Pumps and Emergency Generators

Equipment Type	Number	Hours/Day	Hours/Year	Horse Power	Load Factor	Fuel Type

Boilers

Equipment Type	Number	Heat Input/Day	Heat Input/Year	Boiler Rating	Fuel Type

User Defined Equipment

Equipment Type	Number

11.0 Vegetation

SCR-FCCU

Los Angeles-South Coast County, Winter

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
Industrial Park	3.01	1000sqft	0.07	3,014.00	0

1.2 Other Project Characteristics

Urbanization Urban **Wind Speed (m/s)** 2.2 **Precipitation Freq (Days)** 33

Climate Zone 11 **Operational Year** 2021

Utility Company Los Angeles Department of Water & Power

CO2 Intensity (lb/MWhr) 1227.89 **CH4 Intensity (lb/MWhr)** 0.029 **N2O Intensity (lb/MWhr)** 0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics - Some facilities use SCE while others use LADWP, model here uses LADWP to generate conservative GHG values.

Land Use - Lot Acreage based on 2015 NOX RECLAIM ANALYSIS: one SCR for FCCU with a plot of 2475 sq.ft + one 11,000-gallon ammonia tank with a plot of 539 sq.ft.

Construction Phase - 015 NOx RECLAIM assumed 12 months (260 days) of construction duration.

Off-road Equipment - Equipment from 2015 NOX RECLAIM EA's Appendix E-2, added an off-highway truck to represent water truck.

Trips and VMT - Based on 2015 NOx RECLAIM EA's Appendix E-2, assume 1 haul truck because the EA assumed 1 ton/day of material trucked away.

Construction Off-road Equipment Mitigation - Tier 4 final for all equipment that is 50hp or greater.

Off-road Equipment - Equipment list per 2015 NOx RECLAIM EA's Appendix E-2, added 1 off-highway truck to represent water truck, added Rubber Tired Dozer of 0 usage only to enable entry on next page.

Grading - Assume 3 ft cut of the 3,014 sq.ft plots (SCR +ammonia tank), and assume all cut material will be exported offsite

Energy Use -

SCR-FCCU - Los Angeles-South Coast County, Winter

Table Name	Column Name	Default Value	New Value
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	2.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	2.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	2.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	3.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstructionPhase	NumDays	2.00	260.00
tblConstructionPhase	PhaseEndDate	6/8/2021	6/2/2022
tblGrading	AcresOfGrading	0.00	0.07
tblGrading	MaterialExported	0.00	334.89
tblOffRoadEquipment	HorsePower	231.00	120.00

tblOffRoadEquipment	LoadFactor	0.31	0.31
tblOffRoadEquipment	LoadFactor	0.38	0.38
tblOffRoadEquipment	LoadFactor	0.37	0.37
tblOffRoadEquipment	OffRoadEquipmentType		Aerial Lifts
tblOffRoadEquipment	OffRoadEquipmentType		Air Compressors
tblOffRoadEquipment	OffRoadEquipmentType		Generator Sets
tblOffRoadEquipment	OffRoadEquipmentType		Off-Highway Trucks
tblOffRoadEquipment	OffRoadEquipmentType		Plate Compactors
tblOffRoadEquipment	OffRoadEquipmentType		Pumps
tblOffRoadEquipment	OffRoadEquipmentType		Tractors/Loaders/Backhoes
tblOffRoadEquipment	OffRoadEquipmentType		Welders
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	UsageHours	8.00	2.00
tblOffRoadEquipment	UsageHours	1.00	0.00
tblOffRoadEquipment	UsageHours	6.00	8.00
tblTripsAndVMT	HaulingTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripLength	6.90	50.00
tblTripsAndVMT	VendorTripNumber	0.00	4.00
tblTripsAndVMT	WorkerTripLength	14.70	25.00
tblTripsAndVMT	WorkerTripNumber	53.00	280.00

2.0 Emissions Summary

2.1 Overall Construction (Maximum Daily Emission)

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2021	6.2059	33.8604	46.9108	0.1089	5.5063	1.6625	7.1688	1.4641	1.6035	3.0676	0.0000	10,497.2667	10,497.2667	1.0032	0.0000	10,522.3467
2022	5.7135	30.7997	45.1752	0.1070	5.5064	1.4346	6.9410	1.4641	1.3841	2.8482	0.0000	10,314.1441	10,314.1441	0.9712	0.0000	10,338.4240
Maximum	**6.2059**	**33.8604**	**46.9108**	**0.1089**	**5.5064**	**1.6625**	**7.1688**	**1.4641**	**1.6035**	**3.0676**	**0.0000**	**10,497.2667**	**10,497.2667**	**1.0032**	**0.0000**	**10,522.3467**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2021	4.1091	12.8147	49.2333	0.1089	5.5060	0.4779	5.9840	1.4641	0.4744	1.9385	0.0000	10,497.2667	10,497.2667	1.0032	0.0000	10,522.3467
2022	3.8538	12.3328	47.7981	0.1070	5.5061	0.4249	5.9310	1.4641	0.4215	1.8856	0.0000	10,314.1441	10,314.1441	0.9712	0.0000	10,338.4240
Maximum	**4.1091**	**12.8147**	**49.2333**	**0.1089**	**5.5061**	**0.4779**	**5.9840**	**1.4641**	**0.4744**	**1.9385**	**0.0000**	**10,497.2667**	**10,497.2667**	**1.0032**	**0.0000**	**10,522.3467**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**33.19**	**61.11**	**-5.37**	**0.00**	**0.00**	**70.85**	**15.56**	**0.00**	**70.01**	**35.36**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	0.0674	0.0000	3.1000e-004	0.0000		0.0000	0.0000		0.0000	0.0000		6.6000e-004	6.6000e-004	0.0000		7.0000e-004
Energy	9.3000e-004	8.4300e-003	7.0800e-003	5.0000e-005		6.4000e-004	6.4000e-004		6.4000e-004	6.4000e-004		10.1131	10.1131	1.9000e-004	1.9000e-004	10.1732
Mobile	0.0417	0.2124	0.5895	2.0800e-003	0.1739	1.8000e-003	0.1757	0.0465	1.6800e-003	0.0482		211.1434	211.1434	0.0113		211.4257
Total	**0.1100**	**0.2209**	**0.5968**	**2.1300e-003**	**0.1739**	**2.4400e-003**	**0.1763**	**0.0465**	**2.3200e-003**	**0.0489**		**221.2571**	**221.2571**	**0.0115**	**1.9000e-004**	**221.5996**

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	0.0674	0.0000	3.1000e-004	0.0000		0.0000	0.0000		0.0000	0.0000		6.6000e-004	6.6000e-004	0.0000		7.0000e-004
Energy	9.3000e-004	8.4300e-003	7.0800e-003	5.0000e-005		6.4000e-004	6.4000e-004		6.4000e-004	6.4000e-004		10.1131	10.1131	1.9000e-004	1.9000e-004	10.1732
Mobile	0.0417	0.2124	0.5895	2.0800e-003	0.1739	1.8000e-003	0.1757	0.0465	1.6800e-003	0.0482		211.1434	211.1434	0.0113		211.4257
Total	**0.1100**	**0.2209**	**0.5968**	**2.1300e-003**	**0.1739**	**2.4400e-003**	**0.1763**	**0.0465**	**2.3200e-003**	**0.0489**		**221.2571**	**221.2571**	**0.0115**	**1.9000e-004**	**221.5996**

SCR-FCCU - Los Angeles-South Coast County, Winter

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Build SCR and ammonia tank for FCCU	Grading	6/7/2021	6/2/2022	5	260	

Acres of Grading (Site Preparation Phase): 0

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0; Striped Parking Area: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Build SCR and ammonia tank for FCCU	Concrete/Industrial Saws	1	2.00	81	0.73
Build SCR and ammonia tank for FCCU	Rubber Tired Dozers	1	0.00	247	0.40
Build SCR and ammonia tank for FCCU	Aerial Lifts	2	2.00	63	0.31
Build SCR and ammonia tank for FCCU	Cranes	1	8.00	120	0.29
Build SCR and ammonia tank for FCCU	Cranes	1	8.00	231	0.29
Build SCR and ammonia tank for FCCU	Forklifts	1	6.00	89	0.20
Build SCR and ammonia tank for FCCU	Air Compressors	1	8.00	78	0.48
Build SCR and ammonia tank for FCCU	Generator Sets	2	8.00	84	0.74
Build SCR and ammonia tank for FCCU	Off-Highway Trucks	3	1.00	402	0.38
Build SCR and ammonia tank for FCCU	Plate Compactors	1	2.00	8	0.43
Build SCR and ammonia tank for FCCU	Pumps	1	2.00	84	0.74
Build SCR and ammonia tank for FCCU	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Build SCR and ammonia tank for FCCU	Welders	5	8.00	46	0.45

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Build SCR and ammonia tank for FCC	21	280.00	4.00	2.00	25.00	50.00	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Use Cleaner Engines for Construction Equipment

Water Exposed Area

3.2 Build SCR and ammonia tank for FCCU - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					4.3000e-004	0.0000	4.3000e-004	5.0000e-005	0.0000	5.0000e-005			0.0000			0.0000
Off-Road	4.0645	30.9588	29.8003	0.0520		1.6155	1.6155		1.5600	1.5600		4,791.7909	4,791.7909	0.8312		4,812.5712
Total	**4.0645**	**30.9588**	**29.8003**	**0.0520**	**4.3000e-004**	**1.6155**	**1.6159**	**5.0000e-005**	**1.5600**	**1.5600**		**4,791.7909**	**4,791.7909**	**0.8312**		**4,812.5712**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	7.0000e-005	2.0900e-003	5.1000e-004	1.0000e-005	2.1000e-004	1.0000e-005	2.2000e-004	6.0000e-005	1.0000e-005	6.0000e-005		0.6398	0.6398	5.0000e-005		0.6410
Vendor	0.0560	1.4009	0.4124	6.0200e-003	0.1849	5.2900e-003	0.1902	0.0532	5.0600e-003	0.0582		642.1316	642.1316	0.0260		642.7822
Worker	2.0854	1.4986	16.6977	0.0508	5.3208	0.0418	5.3625	1.4108	0.0385	1.4493		5,062.7043	5,062.7043	0.1459		5,066.3524
Total	**2.1414**	**2.9016**	**17.1105**	**0.0568**	**5.5059**	**0.0471**	**5.5529**	**1.4641**	**0.0435**	**1.5076**		**5,705.4758**	**5,705.4758**	**0.1720**		**5,709.7755**

3.2 Build SCR and ammonia tank for FCCU - 2021

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					1.7000e-004	0.0000	1.7000e-004	2.0000e-005	0.0000	2.0000e-005			0.0000			0.0000
Off-Road	1.9677	9.9132	32.1228	0.0520		0.4309	0.4309		0.4309	0.4309	0.0000	4,791.7909	4,791.7909	0.8312		4,812.5712
Total	**1.9677**	**9.9132**	**32.1228**	**0.0520**	**1.7000e-004**	**0.4309**	**0.4311**	**2.0000e-005**	**0.4309**	**0.4309**	**0.0000**	**4,791.7909**	**4,791.7909**	**0.8312**		**4,812.5712**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	7.0000e-005	2.0900e-003	5.1000e-004	1.0000e-005	2.1000e-004	1.0000e-005	2.2000e-004	6.0000e-005	1.0000e-005	6.0000e-005		0.6398	0.6398	5.0000e-005		0.6410
Vendor	0.0560	1.4009	0.4124	6.0200e-003	0.1849	5.2900e-003	0.1902	0.0532	5.0600e-003	0.0582		642.1316	642.1316	0.0260		642.7822
Worker	2.0854	1.4986	16.6977	0.0508	5.3208	0.0418	5.3625	1.4108	0.0385	1.4493		5,062.7043	5,062.7043	0.1459		5,066.3524
Total	**2.1414**	**2.9016**	**17.1105**	**0.0568**	**5.5059**	**0.0471**	**5.5529**	**1.4641**	**0.0435**	**1.5076**		**5,705.4758**	**5,705.4758**	**0.1720**		**5,709.7755**

3.2 Build SCR and ammonia tank for FCCU - 2022

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					4.3000e-004	0.0000	4.3000e-004	5.0000e-005	0.0000	5.0000e-005			0.0000			0.0000
Off-Road	3.6977	28.1500	29.3849	0.0520		1.3895	1.3895		1.3424	1.3424		4,792.4592	4,792.4592	0.8137		4,812.8016
Total	**3.6977**	**28.1500**	**29.3849**	**0.0520**	**4.3000e-004**	**1.3895**	**1.3899**	**5.0000e-005**	**1.3424**	**1.3425**		**4,792.4592**	**4,792.4592**	**0.8137**		**4,812.8016**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	6.0000e-005	1.9400e-003	5.1000e-004	1.0000e-005	2.8000e-004	1.0000e-005	2.8000e-004	7.0000e-005	1.0000e-005	8.0000e-005		0.6322	0.6322	5.0000e-005		0.6333
Vendor	0.0530	1.2932	0.3956	5.9600e-003	0.1849	4.6500e-003	0.1896	0.0532	4.4400e-003	0.0576		636.3491	636.3491	0.0256		636.9898
Worker	1.9627	1.3545	15.3942	0.0490	5.3208	0.0404	5.3612	1.4108	0.0373	1.4481		4,884.7037	4,884.7037	0.1318		4,887.9993
Total	**2.0157**	**2.6496**	**15.7903**	**0.0550**	**5.5060**	**0.0451**	**5.5510**	**1.4641**	**0.0417**	**1.5058**		**5,521.6849**	**5,521.6849**	**0.1575**		**5,525.6224**

3.2 Build SCR and ammonia tank for FCCU - 2022

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					1.7000e-004	0.0000	1.7000e-004	2.0000e-005	0.0000	2.0000e-005			0.0000			0.0000
Off-Road	1.8381	9.6832	32.0078	0.0520		0.3798	0.3798		0.3798	0.3798	0.0000	4,792.4592	4,792.4592	0.8137		4,812.8016
Total	**1.8381**	**9.6832**	**32.0078**	**0.0520**	**1.7000e-004**	**0.3798**	**0.3800**	**2.0000e-005**	**0.3798**	**0.3798**	**0.0000**	**4,792.4592**	**4,792.4592**	**0.8137**		**4,812.8016**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	6.0000e-005	1.9400e-003	5.1000e-004	1.0000e-005	2.8000e-004	1.0000e-005	2.8000e-004	7.0000e-005	1.0000e-005	8.0000e-005		0.6322	0.6322	5.0000e-005		0.6333
Vendor	0.0530	1.2932	0.3956	5.9600e-003	0.1849	4.6500e-003	0.1896	0.0532	4.4400e-003	0.0576		636.3491	636.3491	0.0256		636.9898
Worker	1.9627	1.3545	15.3942	0.0490	5.3208	0.0404	5.3612	1.4108	0.0373	1.4481		4,884.7037	4,884.7037	0.1318		4,887.9993
Total	**2.0157**	**2.6496**	**15.7903**	**0.0550**	**5.5060**	**0.0451**	**5.5510**	**1.4641**	**0.0417**	**1.5058**		**5,521.6849**	**5,521.6849**	**0.1575**		**5,525.6224**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	0.0417	0.2124	0.5895	2.0800e-003	0.1739	1.8000e-003	0.1757	0.0465	1.6800e-003	0.0482		211.1434	211.1434	0.0113		211.4257
Unmitigated	0.0417	0.2124	0.5895	2.0800e-003	0.1739	1.8000e-003	0.1757	0.0465	1.6800e-003	0.0482		211.1434	211.1434	0.0113		211.4257

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
Industrial Park	20.56	7.49	2.20	63,905	63,905
Total	20.56	7.49	2.20	63,905	63,905

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
Industrial Park	16.60	8.40	6.90	59.00	28.00	13.00	79	19	2

4.4 Fleet Mix

Land Use	LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
Industrial Park	0.547192	0.045177	0.202743	0.121510	0.016147	0.006143	0.019743	0.029945	0.002479	0.002270	0.005078	0.000682	0.000891

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
NaturalGas Mitigated	9.3000e-004	8.4300e-003	7.0800e-003	5.0000e-005		6.4000e-004	6.4000e-004		6.4000e-004	6.4000e-004		10.1131	10.1131	1.9000e-004	1.9000e-004	10.1732
NaturalGas Unmitigated	9.3000e-004	8.4300e-003	7.0800e-003	5.0000e-005		6.4000e-004	6.4000e-004		6.4000e-004	6.4000e-004		10.1131	10.1131	1.9000e-004	1.9000e-004	10.1732

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
Industrial Park	85.9609	9.3000e-004	8.4300e-003	7.0800e-003	5.0000e-005		6.4000e-004	6.4000e-004		6.4000e-004	6.4000e-004		10.1131	10.1131	1.9000e-004	1.9000e-004	10.1732
Total		**9.3000e-004**	**8.4300e-003**	**7.0800e-003**	**5.0000e-005**		**6.4000e-004**	**6.4000e-004**		**6.4000e-004**	**6.4000e-004**		**10.1131**	**10.1131**	**1.9000e-004**	**1.9000e-004**	**10.1732**

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
Industrial Park	0.0859609	9.3000e-004	8.4300e-003	7.0800e-003	5.0000e-005		6.4000e-004	6.4000e-004		6.4000e-004	6.4000e-004		10.1131	10.1131	1.9000e-004	1.9000e-004	10.1732
Total		**9.3000e-004**	**8.4300e-003**	**7.0800e-003**	**5.0000e-005**		**6.4000e-004**	**6.4000e-004**		**6.4000e-004**	**6.4000e-004**		**10.1131**	**10.1131**	**1.9000e-004**	**1.9000e-004**	**10.1732**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	0.0674	0.0000	3.1000e-004	0.0000		0.0000	0.0000		0.0000	0.0000		6.6000e-004	6.6000e-004	0.0000		7.0000e-004
Unmitigated	0.0674	0.0000	3.1000e-004	0.0000		0.0000	0.0000		0.0000	0.0000		6.6000e-004	6.6000e-004	0.0000		7.0000e-004

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	7.6500e-003					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.0597					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	3.0000e-005	0.0000	3.1000e-004	0.0000		0.0000	0.0000		0.0000	0.0000		6.6000e-004	6.6000e-004	0.0000		7.0000e-004
Total	**0.0674**	**0.0000**	**3.1000e-004**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**6.6000e-004**	**6.6000e-004**	**0.0000**		**7.0000e-004**

6.2 Area by SubCategory

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	7.6500e-003					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.0597					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	3.0000e-005	0.0000	3.1000e-004	0.0000		0.0000	0.0000		0.0000	0.0000		6.6000e-004	6.6000e-004	0.0000		7.0000e-004
Total	**0.0674**	**0.0000**	**3.1000e-004**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**6.6000e-004**	**6.6000e-004**	**0.0000**		**7.0000e-004**

7.0 Water Detail

7.1 Mitigation Measures Water

8.0 Waste Detail

8.1 Mitigation Measures Waste

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Stationary Equipment

Fire Pumps and Emergency Generators

Equipment Type	Number	Hours/Day	Hours/Year	Horse Power	Load Factor	Fuel Type

Boilers

Equipment Type	Number	Heat Input/Day	Heat Input/Year	Boiler Rating	Fuel Type

User Defined Equipment

Equipment Type	Number

11.0 Vegetation

SCR-FCCU

Los Angeles-South Coast County, Mitigation Report

Construction Mitigation Summary

Phase	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Percent Reduction												
Build SCR and ammonia tank for FCCU	0.35	0.61	-0.05	0.00	0.71	0.70	0.00	0.00	0.00	0.00	0.00	0.00

OFFROAD Equipment Mitigation

Equipment Type	Fuel Type	Tier	Number Mitigated	Total Number of Equipment	DPF	Oxidation Catalyst
Concrete/Industrial Saws	Diesel	Tier 4 Final	1	1	No Change	0.00
Rubber Tired Dozers	Diesel	Tier 4 Final	1	1	No Change	0.00
Aerial Lifts	Diesel	Tier 4 Final	2	2	No Change	0.00
Cranes	Diesel	Tier 4 Final	2	2	No Change	0.00
Forklifts	Diesel	Tier 4 Final	1	1	No Change	0.00
Air Compressors	Diesel	Tier 4 Final	1	1	No Change	0.00
Generator Sets	Diesel	Tier 4 Final	2	2	No Change	0.00
Off-Highway Trucks	Diesel	Tier 4 Final	3	3	No Change	0.00
Plate Compactors	Diesel	No Change	0	1	No Change	0.00
Tractors/Loaders/Backhoes	Diesel	Tier 4 Final	1	1	No Change	0.00
Pumps	Diesel	Tier 4 Final	1	1	No Change	0.00
Welders	Diesel	No Change	0	5	No Change	0.00

Equipment Type	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	Unmitigated tons/yr						Unmitigated mt/yr					
Aerial Lifts	2.37000E-003	3.75700E-002	7.04300E-002	1.10000E-004	7.10000E-004	6.50000E-004	0.00000E+000	9.49686E+000	9.49686E+000	3.07000E-003	0.00000E+000	9.57365E+000
Air Compressors	3.67500E-002	2.55030E-001	3.13540E-001	5.10000E-004	1.53500E-002	1.53500E-002	0.00000E+000	4.40862E+001	4.40862E+001	2.96000E-003	0.00000E+000	4.41602E+001
Concrete/Industrial Saws	1.20900E-002	9.51300E-002	1.18820E-001	2.00000E-004	5.29000E-003	5.29000E-003	0.00000E+000	1.74066E+001	1.74066E+001	9.80000E-004	0.00000E+000	1.74313E+001
Cranes	1.00610E-001	1.02778E+000	5.71840E-001	1.13000E-003	5.41400E-002	4.98100E-002	0.00000E+000	9.95301E+001	9.95301E+001	3.21900E-002	0.00000E+000	1.00335E+002
Forklifts	1.19200E-002	1.09440E-001	1.12850E-001	1.50000E-004	7.56000E-003	6.96000E-003	0.00000E+000	1.30430E+001	1.30430E+001	4.22000E-003	0.00000E+000	1.31485E+001
Generator Sets	8.95800E-002	7.94100E-001	9.53380E-001	1.70000E-003	4.11700E-002	4.11700E-002	0.00000E+000	1.46389E+002	1.46389E+002	7.25000E-003	0.00000E+000	1.46570E+002
Off-Highway Trucks	2.79800E-002	2.31210E-001	1.70870E-001	6.40000E-004	8.45000E-003	7.78000E-003	0.00000E+000	5.66158E+001	5.66158E+001	1.83100E-002	0.00000E+000	5.70735E+001
Plate Compactors	1.30000E-003	8.14000E-003	6.81000E-003	2.00000E-005	3.20000E-004	3.20000E-004	0.00000E+000	1.01266E+000	1.01266E+000	1.10000E-004	0.00000E+000	1.01529E+000
Pumps	1.19300E-002	1.00640E-001	1.20980E-001	2.10000E-004	5.45000E-003	5.45000E-003	0.00000E+000	1.82986E+001	1.82986E+001	9.70000E-004	0.00000E+000	1.83229E+001
Rubber Tired Dozers	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000
Tractors/Loaders/Backhoes	2.29300E-002	2.32560E-001	2.90300E-001	4.00000E-004	1.32400E-002	1.21800E-002	0.00000E+000	3.52232E+001	3.52232E+001	1.13900E-002	0.00000E+000	3.55080E+001
Welders	1.88910E-001	9.64480E-001	1.10667E+000	1.65000E-003	4.52000E-002	4.52000E-002	0.00000E+000	1.21873E+002	1.21873E+002	1.53300E-002	0.00000E+000	1.22256E+002

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Equipment Type	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Mitigated tons/yr							Mitigated mt/yr					
Aerial Lifts	2.66000E-003	6.07600E-002	8.20400E-002	1.10000E-004	1.80000E-004	1.80000E-004	0.00000E+000	9.49685E+000	9.49685E+000	3.07000E-003	0.00000E+000	9.57363E+000
Air Compressors	5.13000E-003	2.22300E-002	3.16400E-001	5.10000E-004	6.80000E-004	6.80000E-004	0.00000E+000	4.40861E+001	4.40861E+001	2.96000E-003	0.00000E+000	4.41601E+001
Concrete/Industrial Saws	2.03000E-003	8.78000E-003	1.24920E-001	2.00000E-004	2.70000E-004	2.70000E-004	0.00000E+000	1.74066E+001	1.74066E+001	9.80000E-004	0.00000E+000	1.74312E+001
Cranes	1.39500E-002	6.04500E-002	6.30700E-001	1.13000E-003	1.86000E-003	1.86000E-003	0.00000E+000	9.95300E+001	9.95300E+001	3.21900E-002	0.00000E+000	1.00335E+002
Forklifts	1.83000E-003	7.93000E-003	1.12820E-001	1.50000E-004	2.40000E-004	2.40000E-004	0.00000E+000	1.30430E+001	1.30430E+001	4.22000E-003	0.00000E+000	1.31485E+001
Generator Sets	1.70400E-002	7.38300E-002	1.05060E+000	1.70000E-003	2.27000E-003	2.27000E-003	0.00000E+000	1.46389E+002	1.46389E+002	7.25000E-003	0.00000E+000	1.46570E+002
Off-Highway Trucks	7.89000E-003	3.41900E-002	2.89280E-001	6.40000E-004	1.05000E-003	1.05000E-003	0.00000E+000	5.66157E+001	5.66157E+001	1.83100E-002	0.00000E+000	5.70735E+001
Plate Compactors	1.30000E-003	8.14000E-003	6.81000E-003	2.00000E-005	3.20000E-004	3.20000E-004	0.00000E+000	1.01266E+000	1.01266E+000	1.10000E-004	0.00000E+000	1.01529E+000
Pumps	2.13000E-003	9.23000E-003	1.31320E-001	2.10000E-004	2.80000E-004	2.80000E-004	0.00000E+000	1.82986E+001	1.82986E+001	9.70000E-004	0.00000E+000	1.83229E+001
Rubber Tired Dozers	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000
Tractors/Loaders/Backhoes	4.90000E-003	2.12300E-002	3.02070E-001	4.00000E-004	6.50000E-004	6.50000E-004	0.00000E+000	3.52232E+001	3.52232E+001	1.13900E-002	0.00000E+000	3.55080E+001
Welders	1.88910E-001	9.64480E-001	1.10667E+000	1.65000E-003	4.52000E-002	4.52000E-002	0.00000E+000	1.21873E+002	1.21873E+002	1.53300E-002	0.00000E+000	1.22256E+002

CalEEMod Version: CalEEMod.2016.3.2 Page 4 of 9 Date: 1/12/2021 5:52 PM

Equipment Type	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Percent Reduction												
Aerial Lifts	-1.22363E-001	-6.17248E-001	-1.64845E-001	0.00000E+000	7.46479E-001	7.23077E-001	0.00000E+000	1.05298E-006	1.05298E-006	0.00000E+000	0.00000E+000	2.08907E-006
Air Compressors	8.60408E-001	9.12834E-001	-9.12164E-003	0.00000E+000	9.55700E-001	9.55700E-001	0.00000E+000	1.13414E-006	1.13414E-006	0.00000E+000	0.00000E+000	1.35869E-006
Concrete/Industrial Saws	8.32093E-001	9.07705E-001	-5.13382E-002	0.00000E+000	9.48960E-001	9.48960E-001	0.00000E+000	1.14899E-006	1.14899E-006	0.00000E+000	0.00000E+000	1.14736E-006
Cranes	8.61346E-001	9.41184E-001	-1.02931E-001	0.00000E+000	9.65645E-001	9.62658E-001	0.00000E+000	1.20567E-006	1.20567E-006	0.00000E+000	0.00000E+000	1.19600E-006
Forklifts	8.46477E-001	9.27540E-001	2.65840E-004	0.00000E+000	9.68254E-001	9.65517E-001	0.00000E+000	7.66692E-007	7.66692E-007	0.00000E+000	0.00000E+000	7.60543E-007
Generator Sets	8.09779E-001	9.07027E-001	-1.01974E-001	0.00000E+000	9.44863E-001	9.44863E-001	0.00000E+000	1.16129E-006	1.16129E-006	0.00000E+000	0.00000E+000	1.15985E-006
Off-Highway Trucks	7.18013E-001	8.52126E-001	-6.92983E-001	0.00000E+000	8.75740E-001	8.65039E-001	0.00000E+000	1.23640E-006	1.23640E-006	0.00000E+000	0.00000E+000	1.22649E-006
Plate Compactors	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000
Pumps	8.21459E-001	9.08287E-001	-8.54687E-002	0.00000E+000	9.48624E-001	9.48624E-001	0.00000E+000	1.09298E-006	1.09298E-006	0.00000E+000	0.00000E+000	1.63730E-006
Rubber Tired Dozers	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000
Tractors/Loaders/Backhoes	7.86306E-001	9.08712E-001	-4.05443E-002	0.00000E+000	9.50906E-001	9.46634E-001	0.00000E+000	1.13561E-006	1.13561E-006	0.00000E+000	0.00000E+000	1.12651E-006
Welders	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	1.23079E-006	1.23079E-006	0.00000E+000	0.00000E+000	1.22693E-006

Fugitive Dust Mitigation

Yes/No	Mitigation Measure	Mitigation Input		Mitigation Input		Mitigation Input	
No	Soil Stabilizer for unpaved Roads	PM10 Reduction	0.00	PM2.5 Reduction	0.00		
No	Replace Ground Cover of Area Disturbed	PM10 Reduction	0.00	PM2.5 Reduction	0.00		
Yes	Water Exposed Area	PM10 Reduction	61.00	PM2.5 Reduction	61.00	Frequency (per day)	3.00
No	Unpaved Road Mitigation	Moisture Content %	0.00	Vehicle Speed (mph)	0.00		

No	Clean Paved Road	% PM Reduction	0.00				

		Unmitigated		Mitigated		Percent Reduction	
Phase	Source	PM10	PM2.5	PM10	PM2.5	PM10	PM2.5
Build SCR and ammonia tank for FCCU	Fugitive Dust	0.00	0.00	0.00	0.00	0.64	0.00
Build SCR and ammonia tank for FCCU	Roads	0.70	0.19	0.70	0.19	0.00	0.00

Operational Percent Reduction Summary

Category	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio-CO2	Total CO2	CH4	N2O	CO2e
Percent Reduction												
Architectural Coating	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Consumer Products	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hearth	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Landscaping	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mobile	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Indoor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Outdoor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Operational Mobile Mitigation

Project Setting:

Mitigation	Category	Measure	% Reduction	Input Value 1	Input Value 2	Input Value

No	Land Use	Increase Density	0.00			
No	Land Use	Increase Diversity	-0.01	0.13		
No	Land Use	Improve Walkability Design	0.00			
No	Land Use	Improve Destination Accessibility	0.00			
No	Land Use	Increase Transit Accessibility	0.25			
No	Land Use	Integrate Below Market Rate Housing	0.00			
	Land Use	Land Use SubTotal	0.00			
No	Neighborhood Enhancements	Improve Pedestrian Network				
No	Neighborhood Enhancements	Provide Traffic Calming Measures				
No	Neighborhood Enhancements	Implement NEV Network	0.00			
	Neighborhood Enhancements	Neighborhood Enhancements Subtotal	0.00			
No	Parking Policy Pricing	Limit Parking Supply	0.00			
No	Parking Policy Pricing	Unbundle Parking Costs	0.00			
No	Parking Policy Pricing	On-street Market Pricing	0.00			
	Parking Policy Pricing	Parking Policy Pricing Subtotal	0.00			
No	Transit Improvements	Provide BRT System	0.00			
No	Transit Improvements	Expand Transit Network	0.00			
No	Transit Improvements	Increase Transit Frequency	0.00			
	Transit Improvements	Transit Improvements Subtotal	0.00			
		Land Use and Site Enhancement Subtotal	0.00			
No	Commute	Implement Trip Reduction Program				
No	Commute	Transit Subsidy				
No	Commute	Implement Employee Parking "Cash Out"				

No	Commute	Workplace Parking Charge				
No	Commute	Encourage Telecommuting and Alternative Work Schedules	0.00			
No	Commute	Market Commute Trip Reduction Option	0.00			
No	Commute	Employee Vanpool/Shuttle	0.00		2.00	
No	Commute	Provide Ride Sharing Program				
	Commute	Commute Subtotal	0.00			
No	School Trip	Implement School Bus Program	0.00			
		Total VMT Reduction	0.00			

Area Mitigation

Measure Implemented	Mitigation Measure	Input Value
No	Only Natural Gas Hearth	
No	No Hearth	
No	Use Low VOC Cleaning Supplies	
No	Use Low VOC Paint (Residential Interior)	50.00
No	Use Low VOC Paint (Residential Exterior)	50.00
No	Use Low VOC Paint (Non-residential Interior)	100.00
No	Use Low VOC Paint (Non-residential Exterior)	100.00
No	Use Low VOC Paint (Parking)	100.00
No	% Electric Lawnmower	
No	% Electric Leafblower	
No	% Electric Chainsaw	

Energy Mitigation Measures

Measure Implemented	Mitigation Measure	Input Value 1	Input Value 2
No	Exceed Title 24		
No	Install High Efficiency Lighting		
No	On-site Renewable		

Appliance Type	Land Use Subtype	% Improvement
ClothWasher		30.00
DishWasher		15.00
Fan		50.00
Refrigerator		15.00

Water Mitigation Measures

Measure Implemented	Mitigation Measure	Input Value 1	Input Value 2
No	Apply Water Conservation on Strategy		
No	Use Reclaimed Water		
No	Use Grey Water		
No	Install low-flow bathroom faucet	32.00	
No	Install low-flow Kitchen faucet	18.00	
No	Install low-flow Toilet	20.00	
No	Install low-flow Shower	20.00	
No	Turf Reduction		
No	Use Water Efficient Irrigation Systems	6.10	
No	Water Efficient Landscape		

Solid Waste Mitigation

Mitigation Measures	Input Value
Institute Recycling and Composting Services Percent Reduction in Waste Disposed	

SCR Upgrade

Los Angeles-South Coast County, Annual

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
Industrial Park	0.00	1000sqft	0.00	0.10	0

1.2 Other Project Characteristics

Urbanization	Urban	**Wind Speed (m/s)**	2.2	**Precipitation Freq (Days)**	33
Climate Zone	11			**Operational Year**	2021
Utility Company	Los Angeles Department of Water & Power				
CO2 Intensity (lb/MWhr)	1227.89	**CH4 Intensity (lb/MWhr)**	0.029	**N2O Intensity (lb/MWhr)**	0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics - Some facilities use SCE while others use LADWP, model here uses LADWP to generate conservative GHG values.

Land Use - Assume no grading activities.

Construction Phase - Assume 1 day for scaffold erection, and 2 weeks for SCR upgrade

Off-road Equipment - Assume 12 hr day installation of scaffold

Off-road Equipment - Assume 12 hr work days.

Trips and VMT - Assume 8 worker-crew for scaffolding, 4 worker-crew for SCR upgrade.

Construction Off-road Equipment Mitigation - Tier 4 final for equipment that is 50 hp or greater.

Energy Use -

SCR Upgrade - Los Angeles-South Coast County, Annual

Table Name	Column Name	Default Value	New Value
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	2.00
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstructionPhase	NumDays	0.00	1.00
tblConstructionPhase	NumDays	0.00	10.00
tblLandUse	LandUseSquareFeet	0.00	0.10
tblOffRoadEquipment	LoadFactor	0.31	0.31
tblOffRoadEquipment	OffRoadEquipmentType		Aerial Lifts
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	UsageHours	4.00	12.00
tblOffRoadEquipment	UsageHours	6.00	12.00
tblOffRoadEquipment	UsageHours	6.00	12.00
tblTripsAndVMT	HaulingTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripLength	6.90	50.00
tblTripsAndVMT	VendorTripLength	6.90	50.00
tblTripsAndVMT	VendorTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripNumber	0.00	2.00
tblTripsAndVMT	WorkerTripLength	14.70	25.00
tblTripsAndVMT	WorkerTripLength	14.70	25.00
tblTripsAndVMT	WorkerTripNumber	0.00	16.00
tblTripsAndVMT	WorkerTripNumber	0.00	8.00

2.0 Emissions Summary

2.1 Overall Construction

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2021	4.9200e-003	0.0550	0.0368	9.0000e-005	1.4100e-003	2.2800e-003	3.6900e-003	3.9000e-004	2.0900e-003	2.4800e-003	0.0000	8.4926	8.4926	2.0400e-003	0.0000	8.5435
Maximum	**4.9200e-003**	**0.0550**	**0.0368**	**9.0000e-005**	**1.4100e-003**	**2.2800e-003**	**3.6900e-003**	**3.9000e-004**	**2.0900e-003**	**2.4800e-003**	**0.0000**	**8.4926**	**8.4926**	**2.0400e-003**	**0.0000**	**8.5435**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2021	1.4800e-003	0.0145	0.0427	9.0000e-005	1.4100e-003	1.3000e-004	1.5500e-003	3.9000e-004	1.3000e-004	5.2000e-004	0.0000	8.4926	8.4926	2.0400e-003	0.0000	8.5435
Maximum	**1.4800e-003**	**0.0145**	**0.0427**	**9.0000e-005**	**1.4100e-003**	**1.3000e-004**	**1.5500e-003**	**3.9000e-004**	**1.3000e-004**	**5.2000e-004**	**0.0000**	**8.4926**	**8.4926**	**2.0400e-003**	**0.0000**	**8.5435**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	**69.92**	**73.69**	**-16.06**	**0.00**	**0.00**	**94.30**	**57.99**	**0.00**	**93.78**	**79.03**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Quarter	Start Date	End Date	Maximum Unmitigated ROG + NOX (tons/quarter)	Maximum Mitigated ROG + NOX (tons/quarter)
		Highest		

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Energy	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	7.8000e-004	7.8000e-004	0.0000	0.0000	7.8000e-004
Mobile	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Waste						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Water						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**7.8000e-004**	**7.8000e-004**	**0.0000**	**0.0000**	**7.8000e-004**

2.2 Overall Operational

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Energy	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	7.8000e-004	7.8000e-004	0.0000	0.0000	7.8000e-004
Mobile	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Waste						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Water						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**7.8000e-004**	**7.8000e-004**	**0.0000**	**0.0000**	**7.8000e-004**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Erecting Scaffold	Building Construction	6/7/2021	6/7/2021	5	1	
2	SCR upgrade	Building Construction	6/8/2021	6/21/2021	5	10	

Acres of Grading (Site Preparation Phase): 0

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0; Striped Parking Area: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Erecting Scaffold	Forklifts	1	12.00	89	0.20
SCR upgrade	Aerial Lifts	1	12.00	63	0.31
SCR upgrade	Cranes	1	12.00	231	0.29
SCR upgrade	Forklifts	1	12.00	89	0.20

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Erecting Scaffold	1	16.00	2.00	0.00	25.00	50.00	20.00	LD_Mix	HDT_Mix	HHDT
SCR upgrade	3	8.00	2.00	2.00	25.00	50.00	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Use Cleaner Engines for Construction Equipment

Water Exposed Area

3.2 Erecting Scaffold - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	1.0000e-004	8.8000e-004	8.8000e-004	0.0000		6.0000e-005	6.0000e-005		6.0000e-005	6.0000e-005	0.0000	0.1007	0.1007	3.0000e-005	0.0000	0.1015
Total	**1.0000e-004**	**8.8000e-004**	**8.8000e-004**	**0.0000**		**6.0000e-005**	**6.0000e-005**		**6.0000e-005**	**6.0000e-005**	**0.0000**	**0.1007**	**0.1007**	**3.0000e-005**	**0.0000**	**0.1015**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	1.0000e-005	3.6000e-004	1.0000e-004	0.0000	5.0000e-005	0.0000	5.0000e-005	1.0000e-005	0.0000	1.0000e-005	0.0000	0.1460	0.1460	1.0000e-005	0.0000	0.1462
Worker	5.0000e-005	4.0000e-005	4.9000e-004	0.0000	1.5000e-004	0.0000	1.5000e-004	4.0000e-005	0.0000	4.0000e-005	0.0000	0.1334	0.1334	0.0000	0.0000	0.1335
Total	**6.0000e-005**	**4.0000e-004**	**5.9000e-004**	**0.0000**	**2.0000e-004**	**0.0000**	**2.0000e-004**	**5.0000e-005**	**0.0000**	**5.0000e-005**	**0.0000**	**0.2795**	**0.2795**	**1.0000e-005**	**0.0000**	**0.2797**

3.2 Erecting Scaffold - 2021

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	1.0000e-005	6.0000e-005	8.7000e-004	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.1007	0.1007	3.0000e-005	0.0000	0.1015
Total	**1.0000e-005**	**6.0000e-005**	**8.7000e-004**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**0.1007**	**0.1007**	**3.0000e-005**	**0.0000**	**0.1015**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	1.0000e-005	3.6000e-004	1.0000e-004	0.0000	5.0000e-005	0.0000	5.0000e-005	1.0000e-005	0.0000	1.0000e-005	0.0000	0.1460	0.1460	1.0000e-005	0.0000	0.1462
Worker	5.0000e-005	4.0000e-005	4.9000e-004	0.0000	1.5000e-004	0.0000	1.5000e-004	4.0000e-005	0.0000	4.0000e-005	0.0000	0.1334	0.1334	0.0000	0.0000	0.1335
Total	**6.0000e-005**	**4.0000e-004**	**5.9000e-004**	**0.0000**	**2.0000e-004**	**0.0000**	**2.0000e-004**	**5.0000e-005**	**0.0000**	**5.0000e-005**	**0.0000**	**0.2795**	**0.2795**	**1.0000e-005**	**0.0000**	**0.2797**

3.3 SCR upgrade - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	4.3500e-003	0.0497	0.0318	7.0000e-005		2.1900e-003	2.1900e-003		2.0100e-003	2.0100e-003	0.0000	5.9088	5.9088	1.9100e-003	0.0000	5.9566
Total	**4.3500e-003**	**0.0497**	**0.0318**	**7.0000e-005**		**2.1900e-003**	**2.1900e-003**		**2.0100e-003**	**2.0100e-003**	**0.0000**	**5.9088**	**5.9088**	**1.9100e-003**	**0.0000**	**5.9566**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	1.0000e-005	2.8000e-004	6.0000e-005	0.0000	2.0000e-005	0.0000	2.0000e-005	0.0000	0.0000	1.0000e-005	0.0000	0.0762	0.0762	1.0000e-005	0.0000	0.0764
Vendor	1.4000e-004	3.5700e-003	1.0200e-003	2.0000e-005	4.5000e-004	1.0000e-005	4.7000e-004	1.3000e-004	1.0000e-005	1.4000e-004	0.0000	1.4603	1.4603	6.0000e-005	0.0000	1.4618
Worker	2.7000e-004	2.2000e-004	2.4600e-003	1.0000e-005	7.5000e-004	1.0000e-005	7.5000e-004	2.0000e-004	1.0000e-005	2.0000e-004	0.0000	0.6671	0.6671	2.0000e-005	0.0000	0.6676
Total	**4.2000e-004**	**4.0700e-003**	**3.5400e-003**	**3.0000e-005**	**1.2200e-003**	**2.0000e-005**	**1.2400e-003**	**3.3000e-004**	**2.0000e-005**	**3.5000e-004**	**0.0000**	**2.2036**	**2.2036**	**9.0000e-005**	**0.0000**	**2.2057**

3.3 SCR upgrade - 2021

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	9.8000e-004	9.9500e-003	0.0377	7.0000e-005		1.1000e-004	1.1000e-004		1.1000e-004	1.1000e-004	0.0000	5.9088	5.9088	1.9100e-003	0.0000	5.9566
Total	**9.8000e-004**	**9.9500e-003**	**0.0377**	**7.0000e-005**		**1.1000e-004**	**1.1000e-004**		**1.1000e-004**	**1.1000e-004**	**0.0000**	**5.9088**	**5.9088**	**1.9100e-003**	**0.0000**	**5.9566**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	1.0000e-005	2.8000e-004	6.0000e-005	0.0000	2.0000e-005	0.0000	2.0000e-005	0.0000	0.0000	1.0000e-005	0.0000	0.0762	0.0762	1.0000e-005	0.0000	0.0764
Vendor	1.4000e-004	3.5700e-003	1.0200e-003	2.0000e-005	4.5000e-004	1.0000e-005	4.7000e-004	1.3000e-004	1.0000e-005	1.4000e-004	0.0000	1.4603	1.4603	6.0000e-005	0.0000	1.4618
Worker	2.7000e-004	2.2000e-004	2.4600e-003	1.0000e-005	7.5000e-004	1.0000e-005	7.5000e-004	2.0000e-004	1.0000e-005	2.0000e-004	0.0000	0.6671	0.6671	2.0000e-005	0.0000	0.6676
Total	**4.2000e-004**	**4.0700e-003**	**3.5400e-003**	**3.0000e-005**	**1.2200e-003**	**2.0000e-005**	**1.2400e-003**	**3.3000e-004**	**2.0000e-005**	**3.5000e-004**	**0.0000**	**2.2036**	**2.2036**	**9.0000e-005**	**0.0000**	**2.2057**

4.0 Operational Detail - Mobile

SCR Upgrade - Los Angeles-South Coast County, Annual

4.1 Mitigation Measures Mobile

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Mitigated	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unmitigated	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
Industrial Park	0.00	0.00	0.00		
Total	0.00	0.00	0.00		

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
Industrial Park	16.60	8.40	6.90	59.00	28.00	13.00	79	19	2

4.4 Fleet Mix

Land Use	LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
Industrial Park	0.547192	0.045177	0.202743	0.121510	0.016147	0.006143	0.019743	0.029945	0.002479	0.002270	0.005078	0.000682	0.000891

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Electricity Mitigated						0.0000	0.0000		0.0000	0.0000	0.0000	7.2000e-004	7.2000e-004	0.0000	0.0000	7.2000e-004
Electricity Unmitigated						0.0000	0.0000		0.0000	0.0000	0.0000	7.2000e-004	7.2000e-004	0.0000	0.0000	7.2000e-004
NaturalGas Mitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	6.0000e-005	6.0000e-005	0.0000	0.0000	6.0000e-005
NaturalGas Unmitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	6.0000e-005	6.0000e-005	0.0000	0.0000	6.0000e-005

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	tons/yr										MT/yr					
Industrial Park	1.041	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	6.0000e-005	6.0000e-005	0.0000	0.0000	6.0000e-005
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**6.0000e-005**	**6.0000e-005**	**0.0000**	**0.0000**	**6.0000e-005**

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	tons/yr										MT/yr					
Industrial Park	1.041	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	6.0000e-005	6.0000e-005	0.0000	0.0000	6.0000e-005
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**6.0000e-005**	**6.0000e-005**	**0.0000**	**0.0000**	**6.0000e-005**

5.3 Energy by Land Use - Electricity

Unmitigated

	Electricity Use	Total CO2	CH4	N2O	CO2e
Land Use	kWh/yr	MT/yr			
Industrial Park	1.299	7.2000e-004	0.0000	0.0000	7.2000e-004
Total		**7.2000e-004**	**0.0000**	**0.0000**	**7.2000e-004**

Mitigated

	Electricity Use	Total CO2	CH4	N2O	CO2e
Land Use	kWh/yr	MT/yr			
Industrial Park	1.299	7.2000e-004	0.0000	0.0000	7.2000e-004
Total		**7.2000e-004**	**0.0000**	**0.0000**	**7.2000e-004**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Mitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unmitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	tons/yr										MT/yr					
Architectural Coating	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Consumer Products	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Landscaping	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

6.2 Area by SubCategory

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	tons/yr										MT/yr					
Architectural Coating	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Consumer Products	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Landscaping	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

7.0 Water Detail

7.1 Mitigation Measures Water

	Total CO2	CH4	N2O	CO2e
Category	MT/yr			
Mitigated	0.0000	0.0000	0.0000	0.0000
Unmitigated	0.0000	0.0000	0.0000	0.0000

7.2 Water by Land Use

Unmitigated

	Indoor/Outdoor Use	Total CO2	CH4	N2O	CO2e
Land Use	Mgal	MT/yr			
Industrial Park	0 / 0	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**

7.2 Water by Land Use

Mitigated

	Indoor/Outdoor Use	Total CO2	CH4	N2O	CO2e
Land Use	Mgal	MT/yr			
Industrial Park	0 / 0	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**

8.0 Waste Detail

8.1 Mitigation Measures Waste

Category/Year

	Total CO2	CH4	N2O	CO2e
	MT/yr			
Mitigated	0.0000	0.0000	0.0000	0.0000
Unmitigated	0.0000	0.0000	0.0000	0.0000

8.2 Waste by Land Use

Unmitigated

	Waste Disposed	Total CO2	CH4	N2O	CO2e
Land Use	tons	MT/yr			
Industrial Park	0	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**

Mitigated

	Waste Disposed	Total CO2	CH4	N2O	CO2e
Land Use	tons	MT/yr			
Industrial Park	0	0.0000	0.0000	0.0000	0.0000
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

SCR Upgrade - Los Angeles-South Coast County, Annual

10.0 Stationary Equipment

Fire Pumps and Emergency Generators

Equipment Type	Number	Hours/Day	Hours/Year	Horse Power	Load Factor	Fuel Type

Boilers

Equipment Type	Number	Heat Input/Day	Heat Input/Year	Boiler Rating	Fuel Type

User Defined Equipment

Equipment Type	Number

11.0 Vegetation

SCR Upgrade

Los Angeles-South Coast County, Summer

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
Industrial Park	0.00	1000sqft	0.00	0.10	0

1.2 Other Project Characteristics

Urbanization	Urban	**Wind Speed (m/s)**	2.2	**Precipitation Freq (Days)**	33
Climate Zone	11			**Operational Year**	2021
Utility Company	Los Angeles Department of Water & Power				
CO2 Intensity (lb/MWhr)	1227.89	**CH4 Intensity (lb/MWhr)**	0.029	**N2O Intensity (lb/MWhr)**	0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics - Some facilities use SCE while others use LADWP, model here uses LADWP to generate conservative GHG values.

Land Use - Assume no grading activities.

Construction Phase - Assume 1 day for scaffold erection, and 2 weeks for SCR upgrade

Off-road Equipment - Assume 12 hr day installation of scaffold

Off-road Equipment - Assume 12 hr work days.

Trips and VMT - Assume 8 worker-crew for scaffolding, 4 worker-crew for SCR upgrade.

Construction Off-road Equipment Mitigation - Tier 4 final for equipment that is 50 hp or greater.

Energy Use -

SCR Upgrade - Los Angeles-South Coast County, Summer

Table Name	Column Name	Default Value	New Value
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	2.00
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstructionPhase	NumDays	0.00	1.00
tblConstructionPhase	NumDays	0.00	10.00
tblLandUse	LandUseSquareFeet	0.00	0.10
tblOffRoadEquipment	LoadFactor	0.31	0.31
tblOffRoadEquipment	OffRoadEquipmentType		Aerial Lifts
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	UsageHours	4.00	12.00
tblOffRoadEquipment	UsageHours	6.00	12.00
tblOffRoadEquipment	UsageHours	6.00	12.00
tblTripsAndVMT	HaulingTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripLength	6.90	50.00
tblTripsAndVMT	VendorTripLength	6.90	50.00
tblTripsAndVMT	VendorTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripNumber	0.00	2.00
tblTripsAndVMT	WorkerTripLength	14.70	25.00
tblTripsAndVMT	WorkerTripLength	14.70	25.00
tblTripsAndVMT	WorkerTripNumber	0.00	16.00
tblTripsAndVMT	WorkerTripNumber	0.00	8.00

2.0 Emissions Summary

2.1 Overall Construction (Maximum Daily Emission)

Unmitigated Construction

Year	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	lb/day										lb/day					
2021	0.9509	10.7121	7.1003	0.0182	0.3965	0.4419	0.6899	0.1072	0.4067	0.4746	0.0000	1,795.8432	1,795.8432	0.4397	0.0000	1,806.8364
Maximum	**0.9509**	**10.7121**	**7.1003**	**0.0182**	**0.3965**	**0.4419**	**0.6899**	**0.1072**	**0.4067**	**0.4746**	**0.0000**	**1,795.8432**	**1,795.8432**	**0.4397**	**0.0000**	**1,806.8364**

Mitigated Construction

Year	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	lb/day										lb/day					
2021	0.2779	2.7644	8.2846	0.0182	0.3965	0.0260	0.4053	0.1072	0.0258	0.1157	0.0000	1,795.8432	1,795.8432	0.4397	0.0000	1,806.8364
Maximum	**0.2779**	**2.7644**	**8.2846**	**0.0182**	**0.3965**	**0.0260**	**0.4053**	**0.1072**	**0.0258**	**0.1157**	**0.0000**	**1,795.8432**	**1,795.8432**	**0.4397**	**0.0000**	**1,806.8364**

SCR Upgrade - Los Angeles-South Coast County, Summer

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	70.78	74.19	-16.68	0.00	0.00	94.11	41.25	0.00	93.65	75.62	0.00	0.00	0.00	0.00	0.00	0.00

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Energy	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		3.4000e-004	3.4000e-004	0.0000	0.0000	3.4000e-004
Mobile	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**		**3.4000e-004**	**3.4000e-004**	**0.0000**	**0.0000**	**3.4000e-004**

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Energy	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		3.4000e-004	3.4000e-004	0.0000	0.0000	3.4000e-004
Mobile	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**		**3.4000e-004**	**3.4000e-004**	**0.0000**	**0.0000**	**3.4000e-004**

SCR Upgrade - Los Angeles-South Coast County, Summer

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Erecting Scaffold	Building Construction	6/7/2021	6/7/2021	5	1	
2	SCR upgrade	Building Construction	6/8/2021	6/21/2021	5	10	

Acres of Grading (Site Preparation Phase): 0

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0; Striped Parking Area: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Erecting Scaffold	Forklifts	1	12.00	89	0.20
SCR upgrade	Aerial Lifts	1	12.00	63	0.31
SCR upgrade	Cranes	1	12.00	231	0.29
SCR upgrade	Forklifts	1	12.00	89	0.20

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Erecting Scaffold	1	16.00	2.00	0.00	25.00	50.00	20.00	LD_Mix	HDT_Mix	HHDT
SCR upgrade	3	8.00	2.00	2.00	25.00	50.00	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Use Cleaner Engines for Construction Equipment

Water Exposed Area

3.2 Erecting Scaffold - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.1940	1.7687	1.7518	2.2900e-003		0.1255	0.1255		0.1155	0.1155		222.0463	222.0463	0.0718		223.8416
Total	**0.1940**	**1.7687**	**1.7518**	**2.2900e-003**		**0.1255**	**0.1255**		**0.1155**	**0.1155**		**222.0463**	**222.0463**	**0.0718**		**223.8416**

3.2 Erecting Scaffold - 2021

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0274	0.6814	0.2023	3.0200e-003	0.0925	2.6300e-003	0.0951	0.0266	2.5200e-003	0.0291		322.5728	322.5728	0.0128		322.8932
Worker	0.1051	0.0773	1.0557	3.0800e-003	0.3040	2.3900e-003	0.3064	0.0806	2.2000e-003	0.0828		307.3474	307.3474	8.9100e-003		307.5701
Total	**0.1326**	**0.7587**	**1.2580**	**6.1000e-003**	**0.3965**	**5.0200e-003**	**0.4015**	**0.1072**	**4.7200e-003**	**0.1119**		**629.9202**	**629.9202**	**0.0217**		**630.4633**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.0283	0.1224	1.7424	2.2900e-003		3.7700e-003	3.7700e-003		3.7700e-003	3.7700e-003	0.0000	222.0463	222.0463	0.0718		223.8416
Total	**0.0283**	**0.1224**	**1.7424**	**2.2900e-003**		**3.7700e-003**	**3.7700e-003**		**3.7700e-003**	**3.7700e-003**	**0.0000**	**222.0463**	**222.0463**	**0.0718**		**223.8416**

3.2 Erecting Scaffold - 2021

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0274	0.6814	0.2023	3.0200e-003	0.0925	2.6300e-003	0.0951	0.0266	2.5200e-003	0.0291		322.5728	322.5728	0.0128		322.8932
Worker	0.1051	0.0773	1.0557	3.0800e-003	0.3040	2.3900e-003	0.3064	0.0806	2.2000e-003	0.0828		307.3474	307.3474	8.9100e-003		307.5701
Total	**0.1326**	**0.7587**	**1.2580**	**6.1000e-003**	**0.3965**	**5.0200e-003**	**0.4015**	**0.1072**	**4.7200e-003**	**0.1119**		**629.9202**	**629.9202**	**0.0217**		**630.4633**

3.3 SCR upgrade - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.8693	9.9384	6.3576	0.0135		0.4380	0.4380		0.4029	0.4029		1,302.6678	1,302.6678	0.4213		1,313.2005
Total	**0.8693**	**9.9384**	**6.3576**	**0.0135**		**0.4380**	**0.4380**		**0.4029**	**0.4029**		**1,302.6678**	**1,302.6678**	**0.4213**		**1,313.2005**

3.3 SCR upgrade - 2021

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	1.6700e-003	0.0537	0.0126	1.6000e-004	3.5000e-003	1.6000e-004	3.6600e-003	9.6000e-004	1.6000e-004	1.1200e-003		16.9289	16.9289	1.1500e-003		16.9577
Vendor	0.0274	0.6814	0.2023	3.0200e-003	0.0925	2.6300e-003	0.0951	0.0266	2.5200e-003	0.0291		322.5728	322.5728	0.0128		322.8932
Worker	0.0526	0.0387	0.5279	1.5400e-003	0.1520	1.1900e-003	0.1532	0.0403	1.1000e-003	0.0414		153.6737	153.6737	4.4600e-003		153.7851
Total	**0.0817**	**0.7737**	**0.7427**	**4.7200e-003**	**0.2480**	**3.9800e-003**	**0.2520**	**0.0679**	**3.7800e-003**	**0.0716**		**493.1754**	**493.1754**	**0.0184**		**493.6359**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.1962	1.9907	7.5419	0.0135		0.0221	0.0221		0.0221	0.0221	0.0000	1,302.6678	1,302.6678	0.4213		1,313.2005
Total	**0.1962**	**1.9907**	**7.5419**	**0.0135**		**0.0221**	**0.0221**		**0.0221**	**0.0221**	**0.0000**	**1,302.6678**	**1,302.6678**	**0.4213**		**1,313.2005**

3.3 SCR upgrade - 2021

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	1.6700e-003	0.0537	0.0126	1.6000e-004	3.5000e-003	1.6000e-004	3.6600e-003	9.6000e-004	1.6000e-004	1.1200e-003		16.9289	16.9289	1.1500e-003		16.9577
Vendor	0.0274	0.6814	0.2023	3.0200e-003	0.0925	2.6300e-003	0.0951	0.0266	2.5200e-003	0.0291		322.5728	322.5728	0.0128		322.8932
Worker	0.0526	0.0387	0.5279	1.5400e-003	0.1520	1.1900e-003	0.1532	0.0403	1.1000e-003	0.0414		153.6737	153.6737	4.4600e-003		153.7851
Total	**0.0817**	**0.7737**	**0.7427**	**4.7200e-003**	**0.2480**	**3.9800e-003**	**0.2520**	**0.0679**	**3.7800e-003**	**0.0716**		**493.1754**	**493.1754**	**0.0184**		**493.6359**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Unmitigated	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
Industrial Park	0.00	0.00	0.00		
Total	0.00	0.00	0.00		

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
Industrial Park	16.60	8.40	6.90	59.00	28.00	13.00	79	19	2

4.4 Fleet Mix

Land Use	LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
Industrial Park	0.547192	0.045177	0.202743	0.121510	0.016147	0.006143	0.019743	0.029945	0.002479	0.002270	0.005078	0.000682	0.000891

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
NaturalGas Mitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		3.4000e-004	3.4000e-004	0.0000	0.0000	3.4000e-004
NaturalGas Unmitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		3.4000e-004	3.4000e-004	0.0000	0.0000	3.4000e-004

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
Industrial Park	0.00285205	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		3.4000e-004	3.4000e-004	0.0000	0.0000	3.4000e-004
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**3.4000e-004**	**3.4000e-004**	**0.0000**	**0.0000**	**3.4000e-004**

5.2 Energy by Land Use - NaturalGas

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
Industrial Park	2.85205e-006	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		3.4000e-004	3.4000e-004	0.0000	0.0000	3.4000e-004
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**3.4000e-004**	**3.4000e-004**	**0.0000**	**0.0000**	**3.4000e-004**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Unmitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000		0.0000

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**		**0.0000**

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**		**0.0000**

7.0 Water Detail

7.1 Mitigation Measures Water

8.0 Waste Detail

8.1 Mitigation Measures Waste

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Stationary Equipment

Fire Pumps and Emergency Generators

Equipment Type	Number	Hours/Day	Hours/Year	Horse Power	Load Factor	Fuel Type

Boilers

Equipment Type	Number	Heat Input/Day	Heat Input/Year	Boiler Rating	Fuel Type

User Defined Equipment

Equipment Type	Number

11.0 Vegetation

SCR Upgrade

Los Angeles-South Coast County, Winter

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
Industrial Park	0.00	1000sqft	0.00	0.10	0

1.2 Other Project Characteristics

Urbanization	Urban	**Wind Speed (m/s)**	2.2	**Precipitation Freq (Days)**	33
Climate Zone	11			**Operational Year**	2021
Utility Company	Los Angeles Department of Water & Power				
CO2 Intensity (lb/MWhr)	1227.89	**CH4 Intensity (lb/MWhr)**	0.029	**N2O Intensity (lb/MWhr)**	0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics - Some facilities use SCE while others use LADWP, model here uses LADWP to generate conservative GHG values.

Land Use - Assume no grading activities.

Construction Phase - Assume 1 day for scaffold erection, and 2 weeks for SCR upgrade

Off-road Equipment - Assume 12 hr day installation of scaffold

Off-road Equipment - Assume 12 hr work days.

Trips and VMT - Assume 8 worker-crew for scaffolding, 4 worker-crew for SCR upgrade.

Construction Off-road Equipment Mitigation - Tier 4 final for equipment that is 50 hp or greater.

Energy Use -

SCR Upgrade - Los Angeles-South Coast County, Winter

Table Name	Column Name	Default Value	New Value
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	1.00
tblConstEquipMitigation	NumberOfEquipmentMitigated	0.00	2.00
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstEquipMitigation	Tier	No Change	Tier 4 Final
tblConstructionPhase	NumDays	0.00	1.00
tblConstructionPhase	NumDays	0.00	10.00
tblLandUse	LandUseSquareFeet	0.00	0.10
tblOffRoadEquipment	LoadFactor	0.31	0.31
tblOffRoadEquipment	OffRoadEquipmentType		Aerial Lifts
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	2.00	1.00
tblOffRoadEquipment	UsageHours	4.00	12.00
tblOffRoadEquipment	UsageHours	6.00	12.00
tblOffRoadEquipment	UsageHours	6.00	12.00
tblTripsAndVMT	HaulingTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripLength	6.90	50.00
tblTripsAndVMT	VendorTripLength	6.90	50.00
tblTripsAndVMT	VendorTripNumber	0.00	2.00
tblTripsAndVMT	VendorTripNumber	0.00	2.00
tblTripsAndVMT	WorkerTripLength	14.70	25.00
tblTripsAndVMT	WorkerTripLength	14.70	25.00
tblTripsAndVMT	WorkerTripNumber	0.00	16.00
tblTripsAndVMT	WorkerTripNumber	0.00	8.00

2.0 Emissions Summary

2.1 Overall Construction (Maximum Daily Emission)

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2021	0.9585	10.7359	7.0542	0.0181	0.3965	0.4420	0.6899	0.1072	0.4067	0.4746	0.0000	1,785.0180	1,785.0180	0.4397	0.0000	1,796.0099
Maximum	**0.9585**	**10.7359**	**7.0542**	**0.0181**	**0.3965**	**0.4420**	**0.6899**	**0.1072**	**0.4067**	**0.4746**	**0.0000**	**1,785.0180**	**1,785.0180**	**0.4397**	**0.0000**	**1,796.0099**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2021	0.2855	2.7883	8.2385	0.0181	0.3965	0.0261	0.4053	0.1072	0.0258	0.1157	0.0000	1,785.0180	1,785.0180	0.4397	0.0000	1,796.0099
Maximum	**0.2855**	**2.7883**	**8.2385**	**0.0181**	**0.3965**	**0.0261**	**0.4053**	**0.1072**	**0.0258**	**0.1157**	**0.0000**	**1,785.0180**	**1,785.0180**	**0.4397**	**0.0000**	**1,796.0099**

SCR Upgrade - Los Angeles-South Coast County, Winter

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	70.21	74.03	-16.79	0.00	0.00	94.10	41.25	0.00	93.65	75.62	0.00	0.00	0.00	0.00	0.00	0.00

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Energy	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		3.4000e-004	3.4000e-004	0.0000	0.0000	3.4000e-004
Mobile	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**		**3.4000e-004**	**3.4000e-004**	**0.0000**	**0.0000**	**3.4000e-004**

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Energy	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		3.4000e-004	3.4000e-004	0.0000	0.0000	3.4000e-004
Mobile	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**		**3.4000e-004**	**3.4000e-004**	**0.0000**	**0.0000**	**3.4000e-004**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Erecting Scaffold	Building Construction	6/7/2021	6/7/2021	5	1	
2	SCR upgrade	Building Construction	6/8/2021	6/21/2021	5	10	

Acres of Grading (Site Preparation Phase): 0

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0; Striped Parking Area: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Erecting Scaffold	Forklifts	1	12.00	89	0.20
SCR upgrade	Aerial Lifts	1	12.00	63	0.31
SCR upgrade	Cranes	1	12.00	231	0.29
SCR upgrade	Forklifts	1	12.00	89	0.20

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Erecting Scaffold	1	16.00	2.00	0.00	25.00	50.00	20.00	LD_Mix	HDT_Mix	HHDT
SCR upgrade	3	8.00	2.00	2.00	25.00	50.00	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Use Cleaner Engines for Construction Equipment

Water Exposed Area

3.2 Erecting Scaffold - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.1940	1.7687	1.7518	2.2900e-003		0.1255	0.1255		0.1155	0.1155		222.0463	222.0463	0.0718		223.8416
Total	**0.1940**	**1.7687**	**1.7518**	**2.2900e-003**		**0.1255**	**0.1255**		**0.1155**	**0.1155**		**222.0463**	**222.0463**	**0.0718**		**223.8416**

3.2 Erecting Scaffold - 2021

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0280	0.7004	0.2062	3.0100e-003	0.0925	2.6400e-003	0.0951	0.0266	2.5300e-003	0.0291		321.0658	321.0658	0.0130		321.3911
Worker	0.1192	0.0856	0.9542	2.9000e-003	0.3040	2.3900e-003	0.3064	0.0806	2.2000e-003	0.0828		289.2974	289.2974	8.3400e-003		289.5059
Total	**0.1472**	**0.7861**	**1.1603**	**5.9100e-003**	**0.3965**	**5.0300e-003**	**0.4015**	**0.1072**	**4.7300e-003**	**0.1119**		**610.3632**	**610.3632**	**0.0214**		**610.8969**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.0283	0.1224	1.7424	2.2900e-003		3.7700e-003	3.7700e-003		3.7700e-003	3.7700e-003	0.0000	222.0463	222.0463	0.0718		223.8416
Total	**0.0283**	**0.1224**	**1.7424**	**2.2900e-003**		**3.7700e-003**	**3.7700e-003**		**3.7700e-003**	**3.7700e-003**	**0.0000**	**222.0463**	**222.0463**	**0.0718**		**223.8416**

3.2 Erecting Scaffold - 2021

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0280	0.7004	0.2062	3.0100e-003	0.0925	2.6400e-003	0.0951	0.0266	2.5300e-003	0.0291		321.0658	321.0658	0.0130		321.3911
Worker	0.1192	0.0856	0.9542	2.9000e-003	0.3040	2.3900e-003	0.3064	0.0806	2.2000e-003	0.0828		289.2974	289.2974	8.3400e-003		289.5059
Total	**0.1472**	**0.7861**	**1.1603**	**5.9100e-003**	**0.3965**	**5.0300e-003**	**0.4015**	**0.1072**	**4.7300e-003**	**0.1119**		**610.3632**	**610.3632**	**0.0214**		**610.8969**

3.3 SCR upgrade - 2021

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.8693	9.9384	6.3576	0.0135		0.4380	0.4380		0.4029	0.4029		1,302.6678	1,302.6678	0.4213		1,313.2005
Total	**0.8693**	**9.9384**	**6.3576**	**0.0135**		**0.4380**	**0.4380**		**0.4029**	**0.4029**		**1,302.6678**	**1,302.6678**	**0.4213**		**1,313.2005**

3.3 SCR upgrade - 2021

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	1.7100e-003	0.0543	0.0133	1.5000e-004	3.5000e-003	1.7000e-004	3.6600e-003	9.6000e-004	1.6000e-004	1.1200e-003		16.6357	16.6357	1.1900e-003		16.6654
Vendor	0.0280	0.7004	0.2062	3.0100e-003	0.0925	2.6400e-003	0.0951	0.0266	2.5300e-003	0.0291		321.0658	321.0658	0.0130		321.3911
Worker	0.0596	0.0428	0.4771	1.4500e-003	0.1520	1.1900e-003	0.1532	0.0403	1.1000e-003	0.0414		144.6487	144.6487	4.1700e-003		144.7529
Total	**0.0893**	**0.7976**	**0.6966**	**4.6100e-003**	**0.2480**	**4.0000e-003**	**0.2520**	**0.0679**	**3.7900e-003**	**0.0716**		**482.3502**	**482.3502**	**0.0184**		**482.8094**

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.1962	1.9907	7.5419	0.0135		0.0221	0.0221		0.0221	0.0221	0.0000	1,302.667 8	1,302.667 8	0.4213		1,313.200 5
Total	**0.1962**	**1.9907**	**7.5419**	**0.0135**		**0.0221**	**0.0221**		**0.0221**	**0.0221**	**0.0000**	**1,302.667 8**	**1,302.667 8**	**0.4213**		**1,313.200 5**

3.3 SCR upgrade - 2021

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	1.7100e-003	0.0543	0.0133	1.5000e-004	3.5000e-003	1.7000e-004	3.6600e-003	9.6000e-004	1.6000e-004	1.1200e-003		16.6357	16.6357	1.1900e-003		16.6654
Vendor	0.0280	0.7004	0.2062	3.0100e-003	0.0925	2.6400e-003	0.0951	0.0266	2.5300e-003	0.0291		321.0658	321.0658	0.0130		321.3911
Worker	0.0596	0.0428	0.4771	1.4500e-003	0.1520	1.1900e-003	0.1532	0.0403	1.1000e-003	0.0414		144.6487	144.6487	4.1700e-003		144.7529
Total	**0.0893**	**0.7976**	**0.6966**	**4.6100e-003**	**0.2480**	**4.0000e-003**	**0.2520**	**0.0679**	**3.7900e-003**	**0.0716**		**482.3502**	**482.3502**	**0.0184**		**482.8094**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Unmitigated	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
Industrial Park	0.00	0.00	0.00		
Total	0.00	0.00	0.00		

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
Industrial Park	16.60	8.40	6.90	59.00	28.00	13.00	79	19	2

4.4 Fleet Mix

Land Use	LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
Industrial Park	0.547192	0.045177	0.202743	0.121510	0.016147	0.006143	0.019743	0.029945	0.002479	0.002270	0.005078	0.000682	0.000891

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
NaturalGas Mitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		3.4000e-004	3.4000e-004	0.0000	0.0000	3.4000e-004
NaturalGas Unmitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		3.4000e-004	3.4000e-004	0.0000	0.0000	3.4000e-004

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
Industrial Park	0.00285205	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		3.4000e-004	3.4000e-004	0.0000	0.0000	3.4000e-004
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**3.4000e-004**	**3.4000e-004**	**0.0000**	**0.0000**	**3.4000e-004**

5.2 Energy by Land Use - NaturalGas

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
Industrial Park	2.85205e-006	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		3.4000e-004	3.4000e-004	0.0000	0.0000	3.4000e-004
Total		**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**3.4000e-004**	**3.4000e-004**	**0.0000**	**0.0000**	**3.4000e-004**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Unmitigated	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000		0.0000

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**		**0.0000**

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**		**0.0000**

7.0 Water Detail

7.1 Mitigation Measures Water

8.0 Waste Detail

8.1 Mitigation Measures Waste

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Stationary Equipment

Fire Pumps and Emergency Generators

Equipment Type	Number	Hours/Day	Hours/Year	Horse Power	Load Factor	Fuel Type

Boilers

Equipment Type	Number	Heat Input/Day	Heat Input/Year	Boiler Rating	Fuel Type

User Defined Equipment

Equipment Type	Number

11.0 Vegetation

SCR Upgrade

Los Angeles-South Coast County, Mitigation Report

Construction Mitigation Summary

Phase	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Percent Reduction												
Erecting Scaffold	0.56	0.64	0.01	0.00	1.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00
SCR upgrade	0.71	0.74	-0.17	0.00	0.94	0.94	0.00	0.00	0.00	0.00	0.00	0.00

OFFROAD Equipment Mitigation

Equipment Type	Fuel Type	Tier	Number Mitigated	Total Number of Equipment	DPF	Oxidation Catalyst
Aerial Lifts	Diesel	Tier 4 Final	1	1	No Change	0.00
Cranes	Diesel	Tier 4 Final	1	1	No Change	0.00
Forklifts	Diesel	Tier 4 Final	2	2	No Change	0.00

Equipment Type	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	Unmitigated tons/yr						Unmitigated mt/yr					
Aerial Lifts	2.80000E-004	4.48000E-003	8.16000E-003	1.00000E-005	9.00000E-005	8.00000E-005	0.00000E+000	1.10002E+000	1.10002E+000	3.60000E-004	0.00000E+000	1.10892E+000
Cranes	3.10000E-003	3.63700E-002	1.48700E-002	4.00000E-005	1.48000E-003	1.36000E-003	0.00000E+000	3.80159E+000	3.80159E+000	1.23000E-003	0.00000E+000	3.83233E+000
Forklifts	1.07000E-003	9.73000E-003	9.63000E-003	1.00000E-005	6.90000E-004	6.40000E-004	0.00000E+000	1.10790E+000	1.10790E+000	3.60000E-004	0.00000E+000	1.11686E+000

Equipment Type	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Mitigated tons/yr							Mitigated mt/yr					
Aerial Lifts	3.10000E-004	7.04000E-003	9.50000E-003	1.00000E-005	2.00000E-005	2.00000E-005	0.00000E+000	1.10002E+000	1.10002E+000	3.60000E-004	0.00000E+000	1.10892E+000
Cranes	5.30000E-004	2.30000E-003	1.94900E-002	4.00000E-005	7.00000E-005	7.00000E-005	0.00000E+000	3.80159E+000	3.80159E+000	1.23000E-003	0.00000E+000	3.83233E+000
Forklifts	1.60000E-004	6.70000E-004	9.58000E-003	1.00000E-005	2.00000E-005	2.00000E-005	0.00000E+000	1.10790E+000	1.10790E+000	3.60000E-004	0.00000E+000	1.11686E+000

Equipment Type	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Percent Reduction												
Aerial Lifts	-1.07143E-001	-5.71429E-001	-1.64216E-001	0.00000E+000	7.77778E-001	7.50000E-001	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000
Cranes	8.29032E-001	9.36761E-001	-3.10693E-001	0.00000E+000	9.52703E-001	9.48529E-001	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000
Forklifts	8.50467E-001	9.31141E-001	5.19211E-003	0.00000E+000	9.71014E-001	9.68750E-001	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000	0.00000E+000

Fugitive Dust Mitigation

Yes/No	Mitigation Measure	Mitigation Input		Mitigation Input		Mitigation Input	
No	Soil Stabilizer for unpaved Roads	PM10 Reduction	0.00	PM2.5 Reduction	0.00		
No	Replace Ground Cover of Area Disturbed	PM10 Reduction	0.00	PM2.5 Reduction	0.00		
Yes	Water Exposed Area	PM10 Reduction	61.00	PM2.5 Reduction	61.00	Frequency (per day)	3.00
No	Unpaved Road Mitigation	Moisture Content %	0.00	Vehicle Speed (mph)	0.00		
No	Clean Paved Road	% PM Reduction	0.00				

		Unmitigated		Mitigated		Percent Reduction	
Phase	Source	PM10	PM2.5	PM10	PM2.5	PM10	PM2.5
Erecting Scaffold	Fugitive Dust	0.00	0.00	0.00	0.00	0.00	0.00
Erecting Scaffold	Roads	0.00	0.00	0.00	0.00	0.00	0.00
SCR upgrade	Fugitive Dust	0.00	0.00	0.00	0.00	0.00	0.00
SCR upgrade	Roads	0.00	0.00	0.00	0.00	0.00	0.00

Operational Percent Reduction Summary

Category	ROG	NOx	CO	SO2	Exhaust PM10	Exhaust PM2.5	Bio- CO2	NBio-CO2	Total CO2	CH4	N2O	CO2e
Percent Reduction												
Architectural Coating	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Consumer Products	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hearth	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Landscaping	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mobile	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Indoor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Outdoor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Operational Mobile Mitigation

Project Setting:

Mitigation	Category	Measure	% Reduction	Input Value 1	Input Value 2	Input Value

No	Land Use	Increase Density	0.00			
No	Land Use	Increase Diversity	-0.01	0.13		
No	Land Use	Improve Walkability Design	0.00			
No	Land Use	Improve Destination Accessibility	0.00			
No	Land Use	Increase Transit Accessibility	0.25			
No	Land Use	Integrate Below Market Rate Housing	0.00			
	Land Use	Land Use SubTotal	0.00			
No	Neighborhood Enhancements	Improve Pedestrian Network				
No	Neighborhood Enhancements	Provide Traffic Calming Measures				
No	Neighborhood Enhancements	Implement NEV Network	0.00			
	Neighborhood Enhancements	Neighborhood Enhancements Subtotal	0.00			
No	Parking Policy Pricing	Limit Parking Supply	0.00			
No	Parking Policy Pricing	Unbundle Parking Costs	0.00			
No	Parking Policy Pricing	On-street Market Pricing	0.00			
	Parking Policy Pricing	Parking Policy Pricing Subtotal	0.00			
No	Transit Improvements	Provide BRT System	0.00			
No	Transit Improvements	Expand Transit Network	0.00			
No	Transit Improvements	Increase Transit Frequency	0.00			
	Transit Improvements	Transit Improvements Subtotal	0.00			
		Land Use and Site Enhancement Subtotal	0.00			
No	Commute	Implement Trip Reduction Program				
No	Commute	Transit Subsidy				
No	Commute	Implement Employee Parking "Cash Out"				

No	Commute	Workplace Parking Charge				
No	Commute	Encourage Telecommuting and Alternative Work Schedules	0.00			
No	Commute	Market Commute Trip Reduction Option	0.00			
No	Commute	Employee Vanpool/Shuttle	0.00		2.00	
No	Commute	Provide Ride Sharing Program				
	Commute	Commute Subtotal	0.00			
No	School Trip	Implement School Bus Program	0.00			
		Total VMT Reduction	0.00			

Area Mitigation

Measure Implemented	Mitigation Measure	Input Value
No	Only Natural Gas Hearth	
No	No Hearth	
No	Use Low VOC Cleaning Supplies	
No	Use Low VOC Paint (Residential Interior)	50.00
No	Use Low VOC Paint (Residential Exterior)	50.00
No	Use Low VOC Paint (Non-residential Interior)	100.00
No	Use Low VOC Paint (Non-residential Exterior)	100.00
No	Use Low VOC Paint (Parking)	100.00
No	% Electric Lawnmower	
No	% Electric Leafblower	
No	% Electric Chainsaw	

Energy Mitigation Measures

Measure Implemented	Mitigation Measure	Input Value 1	Input Value 2
No	Exceed Title 24		
No	Install High Efficiency Lighting		
No	On-site Renewable		

Appliance Type	Land Use Subtype	% Improvement
ClothWasher		30.00
DishWasher		15.00
Fan		50.00
Refrigerator		15.00

Water Mitigation Measures

Measure Implemented	Mitigation Measure	Input Value 1	Input Value 2
No	Apply Water Conservation on Strategy		
No	Use Reclaimed Water		
No	Use Grey Water		
No	Install low-flow bathroom faucet	32.00	
No	Install low-flow Kitchen faucet	18.00	
No	Install low-flow Toilet	20.00	
No	Install low-flow Shower	20.00	
No	Turf Reduction		
No	Use Water Efficient Irrigation Systems	6.10	
No	Water Efficient Landscape		

Solid Waste Mitigation

Mitigation Measures	Input Value
Institute Recycling and Composting Services Percent Reduction in Waste Disposed	

APPENDIX C

CEQA Impact Calculations

Updates were made to calculations originally presented in pgs. C-1 to C-5, and C-9 to C-15 of Appendix C of the Draft SEA to include equipment replacement projects and correct GHG emissions from burner replacement with ULNB. The original pages with accompanying header-footer designations from the Draft SEA have been included in Appendix C of the Final SEA and follow the updated calculations for their respective topics. These are located in this appendix with the Final SEA page numbering as follows:

PR 1109.1 - Unmitigated Air Quality Construction Impacts [Replaces pgs C-1 and C-2 of the September 2021 Draft SEA]

	PR 1109.1 Implementation				Unmitigated						
Anonymous Designation	**New ULNB**	**New SCR BHT**	**New SCR FCCU**	**SCR Upgrade**	**VOC (lbs/day)**	**NOx (lbs/day)**	**CO (lbs/day)**	**SO2 (lbs/day)**	**PM10 Total (lbs/day)**	**PM2.5 Total (lbs/day)**	**CO2e (MT/yr)**
1*											
2	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	2	0	0	0	13.06	122.85	102.59	0.22	7.20	5.93	18.79
4*											
5	14	3	0	1	98.75	915.09	775.50	1.64	56.27	44.99	151.76
6	11	2	0	0	76.08	705.27	597.76	1.26	43.06	34.62	116.64
7	6	2	0	0	43.42	398.15	341.29	0.72	25.05	19.79	69.67
8	4	0	0	0	26.13	245.70	205.17	0.43	14.41	11.86	37.58
9	5	3	0	2	40.92	373.01	320.96	0.68	24.54	18.77	67.49
10	5	1	0	0	34.77	321.93	273.23	0.58	19.73	15.83	53.62
11	2	0	0	0	13.06	122.85	102.59	0.22	7.20	5.93	18.79
12	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00

* Because Representatives from Facility 1 and 4 Provided Mitigated Calculations, Unmitigated Emissions are Not Listed

Facility Code	**PR 1109.1 Implementation**								
1	Heaters/Boilers: ULNB								
	Heaters/Boilers: New SCR								
	Heaters/Boilers: SCR Upgrade								
	Sulfuric Acid Plants: ULNB								
	SRUs: ULNB								
	FCCUs: New SCR								
	FCCUS: SCR Upgrade								
	Thermal Oxidizer: ULNB								
	Gas Turbine: SCR Upgrade								
3	Heaters/Boilers: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	2	13.06	122.85	102.59	0.22	7.20	5.93	18.79
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	Heaters/Boilers: ULNB								
	Heaters/Boilers: New SCR								
	Heaters/Boilers: SCR Upgrade								
	Sulfuric Acid Plants: ULNB								
	SRUs: ULNB								
	FCCUs: New SCR								
	FCCUS: SCR Upgrade								
	Thermal Oxidizer: ULNB								
	Gas Turbine: SCR Upgrade								
5	Heaters/Boilers: ULNB	11	71.85	675.67	564.22	1.19	39.62	32.62	103.35
	Heaters/Boilers: New SCR	3	6.35	44.41	50.30	0.10	5.15	2.99	19.94
	Heaters/Boilers: SCR Upgrade	1	0.96	10.74	7.10	0.02	0.69	0.47	0.28
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	1	6.53	61.42	51.29	0.11	3.60	2.97	9.40
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	2	13.06	122.85	102.59	0.22	7.20	5.93	18.79
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	Heaters/Boilers: ULNB	10	65.32	614.24	512.93	1.09	36.02	29.66	93.96
	Heaters/Boilers: New SCR	2	4.23	29.61	33.53	0.07	3.43	2.00	13.29
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	1	6.53	61.42	51.29	0.11	3.60	2.97	9.40
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	Heaters/Boilers: ULNB	6	39.19	368.55	307.76	0.65	21.61	17.79	56.37
	Heaters/Boilers: New SCR	2	4.23	29.61	33.53	0.07	3.43	2.00	13.29
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00

8	Heaters/Boilers: ULNB	4	26.13	245.70	205.17	0.43	14.41	11.86	37.58
	Heaters/Boilers: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	Heaters/Boilers: ULNB	4	26.13	245.70	205.17	0.43	14.41	11.86	37.58
	Heaters/Boilers: New SCR	3	6.35	44.41	50.30	0.10	5.15	2.99	19.94
	Heaters/Boilers: SCR Upgrade	2	1.92	21.47	14.20	0.04	1.38	0.95	0.57
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	1	6.53	61.42	51.29	0.11	3.60	2.97	9.40
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	Heaters/Boilers: ULNB	1	6.53	61.42	51.29	0.11	3.60	2.97	9.40
	Heaters/Boilers: New SCR	1	2.12	14.80	16.77	0.03	1.72	1.00	6.65
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	1	6.53	61.42	51.29	0.11	3.60	2.97	9.40
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	3	19.59	184.27	153.88	0.33	10.81	8.90	28.19
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	Heaters/Boilers: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	2	13.06	122.85	102.59	0.22	7.20	5.93	18.79
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00

PR 1109.1 - Unmitigated Air Quality Construction Impacts

	PR 1109.1 Implementation				Unmitigated						
Facility Code	**New ULNB**	**New SCR BHT**	**New SCR FCCU**	**SCR Upgrade**	**VOC (lbs/day)**	**NOx (lbs/day)**	**CO (lbs/day)**	**SO2 (lbs/day)**	**PM10 Total (lbs/day)**	**PM2.5 Total (lbs/day)**	**CO2e (MT/yr)**
1	9	3	0	0	77.40	654.40	607.68	1.31	53.93	35.89	161.33
2	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	3	0	0	0	19.59	184.27	153.88	0.33	10.81	8.90	29.72
4	13	6	0	4	125.98	1044.62	987.29	2.16	92.60	58.86	274.27
5	14	3	0	1	98.75	915.09	775.50	1.64	56.27	44.99	158.89
6	11	2	0	0	76.08	705.27	597.76	1.26	43.06	34.62	122.25
7	6	2	0	0	43.42	398.15	341.29	0.72	25.05	19.79	72.72
8	4	0	0	0	26.13	245.70	205.17	0.43	14.41	11.86	39.62
9	5	3	0	2	40.92	373.01	320.96	0.68	24.54	18.77	70.03
10	5	1	0	0	34.77	321.93	273.23	0.58	19.73	15.83	56.17
11	2	0	0	0	13.06	122.85	102.59	0.22	7.20	5.93	19.81
12	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	72	20	0	7	556.11	4965.28	4365.35	9.34	347.59	255.44	1004.81

Facility Code	**PR 1109.1 Implementation**								
1	Heaters/Boilers: ULNB	9	58.78	552.82	461.64	0.98	32.42	26.69	89.15
	Heaters/Boilers: New SCR	3	18.62	101.58	146.04	0.34	21.51	9.20	72.18
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	Heaters/Boilers: ULNB	1	6.53	61.42	51.29	0.11	3.60	2.97	9.91
	Heaters/Boilers: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	2	13.06	122.85	102.59	0.22	7.20	5.93	19.81
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	Heaters/Boilers: ULNB	13	84.91	798.51	666.81	1.41	46.83	38.55	128.77
	Heaters/Boilers: New SCR	6	37.24	203.16	292.08	0.67	43.01	18.41	144.36
	Heaters/Boilers: SCR Upgrade	3	2.88	32.21	21.30	0.05	2.07	1.42	0.85
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	1	0.96	10.74	7.10	0.02	0.69	0.47	0.28
5	Heaters/Boilers: ULNB	11	71.85	675.67	564.22	1.19	39.62	32.62	108.96
	Heaters/Boilers: New SCR	3	6.35	44.41	50.30	0.10	5.15	2.99	19.94
	Heaters/Boilers: SCR Upgrade	1	0.96	10.74	7.10	0.02	0.69	0.47	0.28
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	1	6.53	61.42	51.29	0.11	3.60	2.97	9.91
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	2	13.06	122.85	102.59	0.22	7.20	5.93	19.81
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	Heaters/Boilers: ULNB	10	65.32	614.24	512.93	1.09	36.02	29.66	99.05
	Heaters/Boilers: New SCR	2	4.23	29.61	33.53	0.07	3.43	2.00	13.29
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	1	6.53	61.42	51.29	0.11	3.60	2.97	9.91
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	Heaters/Boilers: ULNB	6	39.19	368.55	307.76	0.65	21.61	17.79	59.43
	Heaters/Boilers: New SCR	2	4.23	29.61	33.53	0.07	3.43	2.00	13.29
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00

8	Heaters/Boilers: ULNB	4	26.13	245.70	205.17	0.43	14.41	11.86	39.62
	Heaters/Boilers: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	Heaters/Boilers: ULNB	4	26.13	245.70	205.17	0.43	14.41	11.86	39.62
	Heaters/Boilers: New SCR	3	6.35	44.41	50.30	0.10	5.15	2.99	19.94
	Heaters/Boilers: SCR Upgrade	2	1.92	21.47	14.20	0.04	1.38	0.95	0.57
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	1	6.53	61.42	51.29	0.11	3.60	2.97	9.91
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	Heaters/Boilers: ULNB	1	6.53	61.42	51.29	0.11	3.60	2.97	9.91
	Heaters/Boilers: New SCR	1	2.12	14.80	16.77	0.03	1.72	1.00	6.65
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	1	6.53	61.42	51.29	0.11	3.60	2.97	9.91
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	3	19.59	184.27	153.88	0.33	10.81	8.90	29.72
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	Heaters/Boilers: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	2	13.06	122.85	102.59	0.22	7.20	5.93	19.81
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00

PR 1109.1 - Mitigated Air Quality Construction Impacts [Replaces pgs C-3 and C-4 of the September 2021 Draft SEA]

	PR 1109.1 Implementation				Mitigated						
Anonymous Designation	**New ULNB**	**New SCR BHT**	**New SCR FCCU**	**SCR Upgrade**	**VOC (lbs/day)**	**NOx (lbs/day)**	**CO (lbs/day)**	**SO2 (lbs/day)**	**PM10 Total (lbs/day)**	**PM2.5 Total (lbs/day)**	**CO2e (MT/yr)**
1*	9	2	0	0	20.07	137.49	585.06	1.13	23.01	8.09	219.00
2	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	2	0	0	0	3.51	18.76	117.66	0.22	1.63	0.79	18.79
4*	2	6	0	1	16.57	180.76	292.67	0.69	49.01	14.48	121.74
5	14	3	0	1	28.35	151.26	883.30	1.64	15.24	6.98	151.76
6	11	2	0	0	21.64	114.61	681.40	1.26	11.25	5.24	116.64
7	6	2	0	0	12.85	67.71	387.24	0.72	7.17	3.26	69.67
8	4	0	0	0	7.03	37.52	235.33	0.43	3.27	1.58	37.58
9	5	3	0	2	12.82	69.62	362.10	0.68	8.29	3.54	67.49
10	5	1	0	0	9.94	52.62	311.28	0.58	5.22	2.42	53.62
11	2	0	0	0	3.51	18.76	117.66	0.22	1.63	0.79	18.79
12	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	60	19	0	4	136.28	849.12	3973.71	7.58	125.71	47.18	875.09

* Add Additional Emissions from Equipment Replacement. GHG Emissions include Emerging Technology Burner Projects. (There is No GHG Mitigation Applied.)

Anonymous Designation	**PR 1109.1 Implementation**								
1	Heaters/Boilers: ULNB	9	15.81	84.42	529.49	0.98	7.35	3.56	84.56
	Heaters/Boilers: New SCR	2	4.26	53.07	55.57	0.15	15.66	4.52	31.09
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	Heaters/Boilers: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	2	3.51	18.76	117.66	0.22	1.63	0.79	18.79
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	Heaters/Boilers: ULNB	2	3.51	18.76	117.66	0.22	1.63	0.79	18.79
	Heaters/Boilers: New SCR	6	12.77	159.21	166.72	0.46	46.97	13.57	93.27
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	1	0.29	2.79	8.28	0.02	0.41	0.12	0.28
5	Heaters/Boilers: ULNB	11	19.32	103.18	647.15	1.19	8.98	4.36	103.35
	Heaters/Boilers: New SCR	3	3.47	17.15	51.37	0.10	3.40	1.32	19.94
	Heaters/Boilers: SCR Upgrade	1	0.29	2.79	8.28	0.02	0.41	0.12	0.28
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	1	1.76	9.38	58.83	0.11	0.82	0.40	9.40
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	2	3.51	18.76	117.66	0.22	1.63	0.79	18.79
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	Heaters/Boilers: ULNB	10	17.57	93.80	588.32	1.09	8.17	3.96	93.96
	Heaters/Boilers: New SCR	2	2.31	11.43	34.25	0.07	2.27	0.88	13.29
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	1	1.76	9.38	58.83	0.11	0.82	0.40	9.40
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	Heaters/Boilers: ULNB	6	10.54	56.28	352.99	0.65	4.90	2.38	56.37
	Heaters/Boilers: New SCR	2	2.31	11.43	34.25	0.07	2.27	0.88	13.29
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00

8	Heaters/Boilers: ULNB	4	7.03	37.52	235.33	0.43	3.27	1.58	37.58
	Heaters/Boilers: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	Heaters/Boilers: ULNB	4	7.03	37.52	235.33	0.43	3.27	1.58	37.58
	Heaters/Boilers: New SCR	3	3.47	17.15	51.37	0.10	3.40	1.32	19.94
	Heaters/Boilers: SCR Upgrade	2	0.57	5.58	16.57	0.04	0.81	0.23	0.57
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	1	1.76	9.38	58.83	0.11	0.82	0.40	9.40
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	Heaters/Boilers: ULNB	1	1.76	9.38	58.83	0.11	0.82	0.40	9.40
	Heaters/Boilers: New SCR	1	1.16	5.72	17.12	0.03	1.13	0.44	6.65
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	1	1.76	9.38	58.83	0.11	0.82	0.40	9.40
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	3	5.27	28.14	176.50	0.33	2.45	1.19	28.19
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	Heaters/Boilers: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	2	3.51	18.76	117.66	0.22	1.63	0.79	18.79
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00

PR 1109.1 - Mitigated Air Quality Construction Impacts

	PR 1109.1 Implementation				Mitigated						
Anonymous Designation	**New ULNB**	**New SCR BHT**	**New SCR FCCU**	**SCR Upgrade**	**VOC (lbs/day)**	**NOx (lbs/day)**	**CO (lbs/day)**	**SO2 (lbs/day)**	**PM10 Total (lbs/day)**	**PM2.5 Total (lbs/day)**	**CO2e (MT/yr)**
1	9	3	0	0	28.14	122.87	682.49	1.31	25.30	9.38	161.33
2	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	3	0	0	0	5.27	28.14	176.50	0.33	2.45	1.19	29.72
4	13	6	0	4	48.64	209.99	1103.97	2.16	48.14	17.24	274.27
5	14	3	0	1	28.35	151.26	883.30	1.64	15.24	6.98	158.89
6	11	2	0	0	21.64	114.61	681.40	1.26	11.25	5.24	122.25
7	6	2	0	0	12.85	67.71	387.24	0.72	7.17	3.26	72.72
8	4	0	0	0	7.03	37.52	235.33	0.43	3.27	1.58	39.62
9	5	3	0	2	12.82	69.62	362.10	0.68	8.29	3.54	70.03
10	5	1	0	0	9.94	52.62	311.28	0.58	5.22	2.42	56.17
11	2	0	0	0	3.51	18.76	117.66	0.22	1.63	0.79	19.81
12	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	72	20	0	7	178.18	873.10	4941.27	9.34	127.95	51.62	1004.81

Anonymous Designation	**PR 1109.1 Implementation**								
1	Heaters/Boilers: ULNB	9	15.81	84.42	529.49	0.98	7.35	3.56	89.15
	Heaters/Boilers: New SCR	3	12.33	38.44	153.01	0.34	17.95	5.82	72.18
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	Heaters/Boilers: ULNB	1	1.76	9.38	58.83	0.11	0.82	0.40	9.91
	Heaters/Boilers: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	2	3.51	18.76	117.66	0.22	1.63	0.79	19.81
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	Heaters/Boilers: ULNB	13	22.84	121.94	764.81	1.41	10.62	5.15	128.77
	Heaters/Boilers: New SCR	6	24.65	76.89	306.02	0.67	35.90	11.63	144.36
	Heaters/Boilers: SCR Upgrade	3	0.86	8.36	24.85	0.05	1.22	0.35	0.85
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	1	0.29	2.79	8.28	0.02	0.41	0.12	0.28
5	Heaters/Boilers: ULNB	11	19.32	103.18	647.15	1.19	8.98	4.36	108.96
	Heaters/Boilers: New SCR	3	3.47	17.15	51.37	0.10	3.40	1.32	19.94
	Heaters/Boilers: SCR Upgrade	1	0.29	2.79	8.28	0.02	0.41	0.12	0.28
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	1	1.76	9.38	58.83	0.11	0.82	0.40	9.91
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	2	3.51	18.76	117.66	0.22	1.63	0.79	19.81
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	Heaters/Boilers: ULNB	10	17.57	93.80	588.32	1.09	8.17	3.96	99.05
	Heaters/Boilers: New SCR	2	2.31	11.43	34.25	0.07	2.27	0.88	13.29
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	1	1.76	9.38	58.83	0.11	0.82	0.40	9.91
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	Heaters/Boilers: ULNB	6	10.54	56.28	352.99	0.65	4.90	2.38	59.43
	Heaters/Boilers: New SCR	2	2.31	11.43	34.25	0.07	2.27	0.88	13.29
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00

	Heaters/Boilers: ULNB	4	7.03	37.52	235.33	0.43	3.27	1.58	39.62
	Heaters/Boilers: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: ULNB	4	7.03	37.52	235.33	0.43	3.27	1.58	39.62
	Heaters/Boilers: New SCR	3	3.47	17.15	51.37	0.10	3.40	1.32	19.94
	Heaters/Boilers: SCR Upgrade	2	0.57	5.58	16.57	0.04	0.81	0.23	0.57
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	SRUs: ULNB	1	1.76	9.38	58.83	0.11	0.82	0.40	9.91
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: ULNB	1	1.76	9.38	58.83	0.11	0.82	0.40	9.91
	Heaters/Boilers: New SCR	1	1.16	5.72	17.12	0.03	1.13	0.44	6.65
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	SRUs: ULNB	1	1.76	9.38	58.83	0.11	0.82	0.40	9.91
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	3	5.27	28.14	176.50	0.33	2.45	1.19	29.72
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Heaters/Boilers: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Sulfuric Acid Plants: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	SRUs: ULNB	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUs: New SCR	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FCCUS: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Thermal Oxidizer: ULNB	2	3.51	18.76	117.66	0.22	1.63	0.79	19.81
	Gas Turbine: SCR Upgrade	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Construction Emissions for Replacing Burner with ULNB (lbs/day) [Replaces pg C-5 of the September 2021 Draft SEA]

	VOC	NOx	CO	SO2	PM10 Total	PM2.5 Total	Season	Total CO2	CH4	N2O	CO2e	CO2e
	lbs/day	lbs/day	lbs/day	lbs/day	lbs/day	lbs/day		MT/yr	MT/yr	MT/yr	MT/yr	MT/yr
Unmitigated	6.5	61.4	51.3	0.1	3.6	3.0	Summer	--	--	--	--	--
	6.5	61.4	51.3	0.1	3.6	3.0	Winter	--	--	--	--	--
Mitigated	1.7	9.4	58.8	0.1	0.8	0.4	Summer	--	--	--	--	--
	1.8	9.4	58.8	0.1	0.8	0.4	Winter	--	--	--	--	--
Unmitigated	**6.5**	**61.4**	**51.3**	**0.1**	**3.6**	**3.0**	--	**280.7**	**0.0**	**0.0**	**281.9**	**9.4**
Mitigated	**1.8**	**9.4**	**58.8**	**0.1**	**0.8**	**0.4**	--	**280.7**	**0.0**	**0.0**	**281.9**	**9.4**

Construction Emissions for Replacing Burner with ULNB (lbs/day)

	VOC	NOx	CO	SO2	PM10 Total	PM2.5 Total	Season	Total CO2	CH4	N2O	CO2e	CO2e
	lbs/day	lbs/day	lbs/day	lbs/day	lbs/day	lbs/day		MT/yr	MT/yr	MT/yr	MT/yr	MT/yr
Unmitigated	6.5	61.4	51.3	0.1	3.6	3.0	Summer	--	--	--	--	--
	6.5	61.4	51.3	0.1	3.6	3.0	Winter	--	--	--	--	--
Mitigated	1.7	9.4	58.8	0.1	0.8	0.4	Summer	--	--	--	--	--
	1.8	9.4	58.8	0.1	0.8	0.4	Winter	--	--	--	--	--
Unmitigated	**6.5**	**61.4**	**51.3**	**0.1**	**3.6**	**3.0**	--	**295.8**	**0.1**	**0.0**	**297.2**	**9.9**
Mitigated	**1.8**	**9.4**	**58.8**	**0.1**	**0.8**	**0.4**	--	**295.8**	**0.1**	**0.0**	**297.2**	**9.9**

SCR Installation for Boilers/Heaters/Gas Turbine															
	VOC	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio- CO2**	**Total CO2**	**CH4**	**N2O**	**CO2e**
	lbs/day										**MT/yr**					
Maximum	2.08	14.75	16.77	0.03	0.95	0.77	1.72	0.26	0.74	1.00	0	198.8795	198.8795	0.0196	0	199.3706
Maximum	2.12	14.80	16.52	0.03	0.95	0.77	1.72	0.26	0.74	1.00						
Maximum	1.12	5.66	17.12	0.03	0.95	0.19	1.13	0.25	0.19	0.44	**0**	**198.88**	**198.88**	**0.0196**	**0**	**199.37**
Maximum	1.16	5.72	16.88	0.03	0.95	0.19	1.13	0.25	0.19	0.44						
Unmitigated	**2.12**	**14.80**	**16.77**	**0.03**	**0.95**	**0.77**	**1.72**	**0.26**	**0.74**	**1.00**	**0.00**	**198.88**	**198.88**	**0.02**	**0.00**	**6.65**
Mitigated	**1.16**	**5.72**	**17.12**	**0.03**	**0.95**	**0.19**	**1.13**	**0.25**	**0.19**	**0.44**	**0.00**	**198.88**	**198.88**	**0.02**	**0.00**	**6.65**

SCR Installation for FCCU

			VOC	NOx	CO	SO2	PM10 Total	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N2O	CO2e
		Year	lbs/day						MT/yr					
Unmitigated	Summer	2021	5.9593	33.677	48.6804	0.1121	7.1688	3.0676		720.11	720.11	0.0684	0	721.82
Unmitigated	Summer	2022	5.4763	30.6342	46.8317	0.1101	6.9409	2.8482		514.07	514.07	0.0481	0	515.28
Unmitigated	**Summer**	**Maximum**	**5.9593**	**33.677**	**48.6804**	**0.1121**	**7.1688**	**3.0676**	**0**	**720.1065**	**720.1065**	**0.0684**	**0**	**721.8169**
Unmitigated	Winter	2021	6.2059	33.8604	46.9108	0.1089	7.1688	3.0676						
Unmitigated	Winter	2022	5.7135	30.7997	45.1752	0.107	6.941	2.8482						
Unmitigated	**Winter**	**Maximum**	**6.2059**	**33.8604**	**46.9108**	**0.1089**	**7.1688**	**3.0676**	**0**	**0**	**0**	**0**	**0**	**0**
Mitigated	Summer	2021	3.8625	12.6314	51.0029	0.1121	5.984	1.9385		720.11	720.11	0.0684	0	721.82
Mitigated	Summer	2022	3.6167	12.1673	49.4547	0.1101	5.931	1.8856		514.07	514.07	0.0481	0	515.28
Mitigated	**Summer**	**Maximum**	**3.8625**	**12.6314**	**51.0029**	**0.1121**	**5.984**	**1.9385**	**0**	**720.1061**	**720.1061**	**0.0684**	**0**	**721.8165**
Mitigated	Winter	2021	4.1091	12.8147	49.2333	0.1089	5.984	1.9385						
Mitigated	Winter	2022	3.8538	12.3328	47.7981	0.107	5.931	1.8856						
Mitigated	**Winter**	**Maximum**	**4.1091**	**12.8147**	**49.2333**	**0.1089**	**5.984**	**1.9385**	**0**	**0**	**0**	**0**	**0**	**0**
Unmitigated			**6.21**	**33.86**	**48.68**	**0.11**	**7.17**	**3.07**	**0.00**	**720.11**	**720.11**	**0.07**	**0.00**	**24.06**
Mitigated			**4.11**	**12.81**	**51.00**	**0.11**	**5.98**	**1.94**	**0.00**	**720.11**	**720.11**	**0.07**	**0.00**	**24.06**

Construction Emissions for SCR Upgrade

		VOC	NOx	CO	SO2	PM10 Total	PM2.5 Total	CO2e
Year		lb/day						MT/yr
Unmitigated	summer	0.9509	10.7121	7.1003	0.0182	0.6899	0.4746	**8.5435**
Mitigated	summer	0.2779	2.7644	8.2846	0.0182	0.4053	0.1157	**8.5435**
Unmitigated	winter	0.9585	10.7359	7.0542	0.0181	0.6899	0.4746	
Mitigated	winter	0.2855	2.7883	8.2385	0.0181	0.4053	0.1157	
Unmitigated		**0.96**	**10.74**	**7.10**	**0.02**	**0.69**	**0.47**	**0.28**
Mitigated		**0.29**	**2.79**	**8.28**	**0.02**	**0.41**	**0.12**	**0.28**

PR 1109.1 - Water Demand for Construction [Replaces pg C-9 of the September 2021 Draft SEA Shown Below]

Water Use from Hydrotesting Storage Tank Integrity (Post-Construction/Pre-Operation):

Refinery ID	plot space (sf) for all control equip	No. of NH3 storage tanks needed	Capacity of Storage Tank (gal)	Plot space (sf) needed per storage tank	Plot space (sf) needed for all storage tanks	Total plot space (sf) for all control equipment & chemical storage	Total acreage disturbed from Construction (acre)	Number of Tanks Overlapping Construction per day (assumes 1/3rd of total number of tanks)	Amount of Water Needed to Hydrotest during Overlap (gal/day)	Amount of Water Needed to Hydrotest for Entire Project (gal/project)
1	150	2	11,000	539	1,078	1,228	0.03	1	11,000	33,000
4	311	12	11,000	539	6,468	6,779	0.16	2	22,000	132,000
5	634	3	11,000	539	1,617	2,251	0.05	1	11,000	33,000
6	1,027	2	11,000	539	1,078	2,105	0.05	1	11,000	22,000
7	570	2	11,000	539	1,078	1,648	0.04	1	11,000	22,000
9	1,276	3	11,000	539	1,617	2,893	0.07	1	11,000	33,000
10	31	1	11,000	539	539	570	0.01	1	11,000	11,000
		25		**Total**	**13,475**	**17,474**	**0.40**	**8**	**88,000**	**286,000**

Note: The December 2015 Final PEA for NOx RECLAIM assumed 400 sf per storage tank, but 539 sf is used to match the offsite consequence analysis for an ammonia spill.

Water Use for Dust Suppresion (during Construction):

Total Area Disturbed, acre	Area Disturbed, ft2	Depth of Water*, ft	Water Use Area, ft3	Water Use, gal	Number of Waterings per day	Total Daily Water Use, gal
0.40	17,474	0.005	87	654	3	**1,961**

*Assumes 1/16 inch depth of water applied per washing

Draft Subsequent Environmental Assessment *Appendix C*

PR 1109.1 – Water Demand for Construction

Water Use from Hydrotesting Storage Tank Integrity (Post-Construction/Pre-Operation):

Refinery ID	plot space (sf) for all control equip	No. of NH3 storage tanks needed	Capacity of Storage Tank (gal)	Plot space (sf) needed per storage tank	Plot space (sf) needed for all storage tanks	Total plot space (sf) for all control equipment & chemical storage	Total acreage disturbed from Construction (acre)	Number of Tanks Overlapping Construction per day (assumes 1/3rd of total number of tanks)	Amount of Water Needed to Hydrotest during Overlap (gal/day)	Amount of Water Needed to Hydrotest for Entire Project (gal/project)
1	150	3	11,000	539	1,617	1,767	0.04	1	11,000	33,000
4	311	6	11,000	539	3,234	3,545	0.08	2	22,000	66,000
5	634	3	11,000	539	1,617	2,251	0.05	1	11,000	33,000
6	1,027	2	11,000	539	1,078	2,105	0.05	1	11,000	22,000
7	570	2	11,000	539	1,078	1,648	0.04	1	11,000	22,000
9	1,276	3	11,000	539	1,617	2,893	0.07	1	11,000	33,000
10	31	1	11,000	539	539	570	0.01	1	11,000	11,000
		20		**Total**	**10,780**	**14,779**	**0.34**	**8**	**88,000**	**220,000**

Note: The December 2015 Final PEA for NOx RECLAIM assumed 400 sf per storage tank, but 539 sf is used to match the offsite consequence analysis for an ammonia spill.

Water Use for Dust Suppresion (during Construction):

Total Area Disturbed, acre	Area Disturbed, ft2	Depth of Water*, ft	Water Use Area, ft3	Water Use, gal	Number of Waterings per day	Total Daily Water Use, gal
0.34	14,779	0.005	74	553	3	**1,658**

*Assumes 1/16 inch depth of water applied per washing

PR 1109.1 et al. *C-9* *September 2021*

PR 1109.1 - Fuel Use for Construction [Replaces pg C-10 of the September 2021 Draft SEA]

GASOLINE	Number of Vehicle Trips per Project				Vehicle Specifications		Project Specifications		Gasoline Gallons per Project			
	ULNB	SCR-BHT	SCR-FCCU	SCR Upgrade	Class	Miles per Gallon	Miles per Trip (ULNB)	Miles per Trip (Other)	ULNB	SCR-BHT	SCR-FCCU	SCR Upgrade
Worker	52	40	280	24	LD_Mix	28.21	14.70	25.00	27.0932	35.44375	248.10625	21.2662502

The December 2015 Final PEA for NOx RECLAIM used EMFAC2007 to estimated fuel usage. The value has been updated with CARB's EMFAC 2017.

DIESEL	Project Hours				Equipment Specifications		
Equipment	ULNB	SCR-BHT	SCR-FCCU	SCR Upgrade	Fuel Usage (gal/hr)	Horsepower	Load Factor
Concrete/Industrial Saws		2	2		3.39	81	0.73
Aerial Lifts		2	4	12	1.12	63	0.31
Cranes	48	8	8	12	1.80	120	0.29
Cranes			8		3.46	231	0.29
Forklifts	60	3	6	24	1.02	89	0.20
Air Compressors	49	1	8		2.15	78	0.48
Generator Sets	36	8	16		3.57	84	0.74
Off-Highway Trucks	4		3		7.89	402	0.38
Plate Compactors		4	2		0.20	8	0.43
Pumps		2	2		3.57	84	0.74
Tractors/Loaders/Backhoes	38	4	8		2.06	97	0.37
Welders	12	16	40		1.19	46	0.45
Bore/Drill Rigs	12				5.70	221	0.50
Cement and Mortar Mixers	4				0.29	9	0.56

Diesel Gallons per Project			
ULNB	SCR-BHT	SCR-FCCU	SCR Upgrade
574.94	92.33	228.90	59.53

The December 2015 Final PEA for NOx RECLAIM used EMFAC2007 to estimated fuel usage. The values have been updated with CARB's EMFAC 2017 Off-road Diesel Emission Factors.
https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/road-documentation/msei-documentation-road

Refinery ID	**ULNB**	**SCR-BHT**	**SCR-FCCU**	**SCR Upgrade**	**Diesel Fuel Usage (gal/all PR 1109.1)**	**Gasoline Fuel Usage (gal/all PR 1109.1)**
1	9	2	0	0	5359	315
3	2	0	0	0	1150	54
4	2	6	0	1	1763	288
5	14	3	0	1	8386	507
6	11	2	0	0	6509	369
7	6	2	0	0	3634	233
8	4	0	0	0	2300	108
9	5	3	0	2	3271	284
10	5	1	0	0	2967	171
11	2	0	0	0	1150	54
				TOTAL	36489	2384

PR 1109.1 - Fuel Use for Construction

GASOLINE	Number of Vehicle Trips per Project				Vehicle Specifications		Project Specifications		Gasoline Gallons per Project			
	ULNB	SCR-BHT	SCR-FCCU	SCR Upgrade	Class	Miles per Gallon	Miles per Trip (ULNB)	Miles per Trip (Other)	ULNB	SCR-BHT	SCR-FCCU	SCR Upgrade
Worker	52	40	280	24	LD_Mix	28.21	14.70	25.00	27.0932	35.44375	248.10625	21.2662502

The December 2015 Final PEA for NOx RECLAIM used EMFAC2007 to estimated fuel usage. The value has been updated with CARB's EMFAC 2017.

DIESEL	Project Hours				Equipment Specifications		
Equipment	ULNB	SCR-BHT	SCR-FCCU	SCR Upgrade	Fuel Usage (gal/hr)	Horsepower	Load Factor
Concrete/Industrial Saws		2	2		3.39	81	0.73
Aerial Lifts		2	4	12	1.12	63	0.31
Cranes	48	8	8	12	1.80	120	0.29
Cranes			8		3.46	231	0.29
Forklifts	60	3	6	24	1.02	89	0.20
Air Compressors	49	1	8		2.15	78	0.48
Generator Sets	36	8	16		3.57	84	0.74
Off-Highway Trucks	4		3		7.89	402	0.38
Plate Compactors		4	2		0.20	8	0.43
Pumps		2	2		3.57	84	0.74
Tractors/Loaders/Backhoes	38	4	8		2.06	97	0.37
Welders	12	16	40		1.19	46	0.45
Bore/Drill Rigs	12				5.70	221	0.50
Cement and Mortar Mixers	4				0.29	9	0.56

Diesel Gallons per Project			
ULNB	SCR-BHT	SCR-FCCU	SCR Upgrade
574.94	92.33	228.90	59.53

The December 2015 Final PEA for NOx RECLAIM used EMFAC2007 to estimated fuel usage. The values have been updated with CARB's EMFAC 2017 Off-road Diesel Emission Factors.
https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/road-documentation/msei-documentation-road

Refinery ID	ULNB	SCR-BHT	SCR-FCCU	SCR Upgrade	Diesel Fuel Usage (gal/all PR 1109.1)	Gasoline Fuel Usage (gal/all PR 1109.1)
1	9	3	0	0	5451	350
3	3	0	0	0	1725	81
4	13	6	0	4	8266	650
5	14	3	0	1	8386	507
6	11	2	0	0	6509	369
7	6	2	0	0	3634	233
8	4	0	0	0	2300	108
9	5	3	0	2	3271	284
10	5	1	0	0	2967	171
11	2	0	0	0	1150	54
				TOTAL	43659	2808

PR 1109.1 Summary of Operational Emissions [Replaces pg C-11 of the September 2021 Draft SEA]

OPERATIONAL PEAK DAILY TOTALS (lb/day)

	VOC	NOx	CO	SOx	PM10	PM2.5
Facility 1	0.08	3.02	0.34	0.01	0.04	0.04
Facility 4	0.08	3.02	0.34	0.01	0.04	0.04
Facility 5	0.06	2.18	0.25	0.01	0.03	0.03
Facility 6	0.08	3.02	0.34	0.01	0.04	0.04
Facility 7	0.08	3.02	0.34	0.01	0.04	0.04
Facility 9	0.08	3.02	0.34	0.01	0.04	0.04
Facility 10	0.08	3.02	0.34	0.01	0.04	0.04
TOTAL	**0.55**	**20.30**	**2.31**	**0.07**	**0.28**	**0.26**

GREENHOUSE GAS TOTALS (MT/yr)

Electricity Calculated when Utility Provider Identified

	Provider	Electricity	Construction	Truck Trips	**TOTALS**
Facility 1	SCE	139	219	1	**359**
Facility 3	SCE		19		**19**
Facility 4	LADWP	351	122	4	**476**
Facility 5	SCE	76	152	1	**228**
Facility 6	SCE	246	117	3	**365**
Facility 7	LADWP	102	70	2	**173**
Facility 8	SCE		38		**38**
Facility 9	LADWP	183	67	3	**253**
Facility 10	SCE	44	54	1	**98**
Facility 11	N/A		19		**19**
TOTALS		**1140**	**875**	**13**	**2029**

Electricity Calculated when Utility Provider Not Identified

	Electricity	Construction	Truck Trips	**TOTALS**
Facility 1	249	219	1	**469**
Facility 3		19		**19**
Facility 4	621	122	4	**747**
Facility 5	136	152	1	**288**
Facility 6	439	117	3	**559**
Facility 7	180	70	2	**251**
Facility 8		38		**38**
Facility 9	324	67	3	**394**
Facility 10	79	54	1	**133**
Facility 11		19		**19**
TOTALS	**2028**	**875**	**13**	**2917**

AMMONIA USAGE TOTALS

	Ammonia Use (gal/year)	Ammonia Use (gal/day)	Ammonia Use (lbs/year)	Ammonia Use (lbs/day)	Ammonia Use (tons/day)	Ammonia Deliveries Per Year	Ammonia Deliveries Peak Day	Catalyst Haul Trip Per Year	Catalyst Delivery Trip Per Year	Catalyst Haul Trip Per Day	Catalyst Delivery Trip Per Day	Notes
Facility 1	20,564	56	157,934	433	0.21634761	3	1	1	1	1	0	
Facility 4	128,265	351	985,076	2,699	1.34941966	19	1	2	2	1	0	
Facility 5	38,921	107	298,917	819	0.40947502	0	0	1	1	1	0	Ammonia ma Ammonia manufactured onsite hence 0 ammonia deliveries
Facility 6	128,354	352	985,758	2,701	1.35035398	19	1	1	1	1	0	
Facility 7	52,586	144	403,864	1,106	0.55323806	8	1	1	1	1	0	
Facility 9	94,922	260	728,998	1,997	0.99862671	14	1	1	1	1	0	
Facility 10	6,486	18	49,816	136	0.06824048	1	1	1	1	1	0	
TOTALS	**470,099**	**1,288**	**3,610,362**	**9,891**	**5**	**64**	**6**	**8**	**8**	**7**	**0**	

FUEL USAGE TOTALS

	Diesel (gal/yr)
Facility 1	101
Facility 4	403
Facility 5	55
Facility 6	347
Facility 7	178
Facility 9	270
Facility 10	71
TOTALS	1426

PR 1109.1 Summary of Operational Emissions

OPERATIONAL PEAK DAILY TOTALS (lb/day)

	VOC	NOx	CO	SOx	PM10	PM2.5
Facility 1	0.08	3.02	0.34	0.01	0.04	0.04
Facility 4	0.08	3.02	0.34	0.01	0.04	0.04
Facility 5	0.06	2.18	0.25	0.01	0.03	0.03
Facility 6	0.08	3.02	0.34	0.01	0.04	0.04
Facility 7	0.08	3.02	0.34	0.01	0.04	0.04
Facility 9	0.08	3.02	0.34	0.01	0.04	0.04
Facility 10	0.08	3.02	0.34	0.01	0.04	0.04
TOTAL	**0.55**	**20.30**	**2.31**	**0.07**	**0.28**	**0.26**

GREENHOUSE GAS TOTALS (MT/yr)

Electricity Calculated when Utility Provider Identified

	Provider	Electricity	Construction	Truck Trips	TOTALS
Facility 1	SCE	209	161	1	**372**
Facility 3	SCE		30		**30**
Facility 4	LADWP	175	274	2	**452**
Facility 5	SCE	76	159	1	**235**
Facility 6	SCE	246	122	3	**371**
Facility 7	LADWP	102	73	2	**176**
Facility 8	SCE		40		**40**
Facility 9	LADWP	183	70	3	**256**
Facility 10	SCE	44	56	1	**101**
Facility 11	N/A		20		**20**
TOTALS		**1035**	**1005**	**12**	**2051**

Electricity Calculated when Utility Provider Not Identified

	Electricity	Construction	Truck Trips	TOTALS
Facility 1	374	161	1	**537**
Facility 3		30		**30**
Facility 4	311	274	2	**587**
Facility 5	136	159	1	**295**
Facility 6	439	122	3	**565**
Facility 7	180	73	2	**254**
Facility 8		40		**40**
Facility 9	324	70	3	**397**
Facility 10	79	56	1	**136**
Facility 11		20		**20**
TOTALS	**1842**	**1005**	**12**	**2859**

AMMONIA USAGE TOTALS

	Ammonia Use (gal/year)	Ammonia Use (gal/day)	Ammonia Use (lbs/year)	Ammonia Use (lbs/day)	Ammonia Use (tons/day)	Ammonia Deliveries Per Year	Ammonia Deliveries Peak Day	Catalyst Haul Trip Per Year	Catalyst Delivery Trip Per Year	Catalyst Haul Trip Per Day	Catalyst Delivery Trip Per Day	Notes
Facility 1	30,846	85	236,901	649	0.32452141	5	1	1	1	1	0	
Facility 4	64,133	176	492,538	1,349	0.67470983	10	1	1	1	1	0	
Facility 5	38,921	107	298,917	819	0.40947502	0	0	1	1	1	0	Ammonia ma Ammonia manufactured onsite hence 0 ammonia deliveries
Facility 6	128,354	352	985,758	2,701	1.35035398	19	1	1	1	1	0	
Facility 7	52,586	144	403,864	1,106	0.55323806	8	1	1	1	1	0	
Facility 9	94,922	260	728,998	1,997	0.99862671	14	1	1	1	1	0	
Facility 10	6,486	18	49,816	136	0.06824048	1	1	1	1	1	0	
TOTALS	**416,249**	**1,140**	**3,196,791**	**8,758**	**4**	**57**	**6**	**7**	**7**	**7**	**0**	

FUEL USAGE TOTALS

	Diesel (gal/yr)
Facility 1	132
Facility 4	209
Facility 5	55
Facility 6	347
Facility 7	178
Facility 9	270
Facility 10	71
TOTALS	1263

OPERATIONAL IMPACTS PER 1 UNIT FOR FACILITY

1 New SCR for 1 Heater/Boiler with One 11,000 gal NH3(aq) Tank

Heaters/Boilers

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	139,784	kWh	383	kWh
Plot Space Needed	49.8835133	sf		
19% Aqueous NH3 Usage at 95% Control	78,967	lb	216	lb
19% Aqueous NH3 Usage at 95% Control	10,282	gal	28	gal
No. of Trucks Delivering 19% Aqueous NH3	2	trucks	1	truck (fixed)
Truck Delivering 19% Aqueous NH3	200	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck (fixed)
Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck (fixed)
Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles

[Replaces pgs C-12 and C-13 of the September 2021 Draft SEA]

TOTAL OPERATIONAL IMPACTS FOR FACILITY

2 New SCR for Heaters/Boilers with 11,000 gal NH3(aq) Tanks

Utility/Infrastructure	Annual Usage		Daily Usage	
Electricity	279,568	kWh	766	kWh
Plot Space Needed	100	sf		
19% Aqueous NH3 Usage at 95% Control	157,934	lb	433	lb
19% Aqueous NH3 Usage at 95% Control	20,564	gal	56	gal
No. of Trucks Delivering 19% Aqueous NH3	3	trucks	1	truck
Truck Delivering 19% Aqueous NH3	300	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck
Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles
Total No. of Trucks	5	trucks	2	trucks
Total Truck Miles	660	miles	360	miles

EQUIPMENT AVERAGES

Heater/Boiler with New SCR	Average Maximum Firing Rating	71.33	MMBTU/hr
	Catalyst Volume	2215.78	ft3
	Catalyst Mass	25354.6	lb

EQUATIONS

Catalyst Volume for 1 SCR for Heater/Boiler or Gas Turbine
= Average Maximum Firing Rating x 16929 / 545*

Number of NH3 Trucks = NH3 Volume in Gallons / 7000 gal per Truck
Number of Spent Catalyst Trucks
= Catalyst Volume x Catalyst Density Factor / 50000 lb Truck / 5 years
Number of Fresh Catalyst Trucks = Number of Spent Catalyst Trucks

OPERATIONS - ON-ROAD VEHICLES AND FUEL USE

Operation	Peak Daily Round-trip Distance (mi/day)	Annual Round-trip Distance (mi/yr)	Mileage Rate (mi/ gal)	2021 Mobile Source Emission Factors							
On-Road Equipment Type				VOC (lb/mi)	CO (lb/mi)	NOx (lb/mi)	SOx (lb/mi)	PM10 (lb/mi)	PM2.5 (lb/mi)	CO2 (lb/mi)	CH4 (lb/mi)
Offsite (Heavy-Heavy Duty Truck)	360	660	6.51	0.00022863	0.00095415	0.00838930	0.00003002	0.00011390	0.00010897	3.17714107	0.00001062

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	0.08	0.34	3.02	0.01	0.04	0.04	1143.77	0.00	1,144
TOTAL	**0**	**0**	**3**	**0**	**0**	**0**	**1,144**	**0**	**1,144**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	2096.91	0.01	2,097	1
TOTAL	**2,097**	**0**	**2,097**	**1**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Peak Day Total Miles (mi/day)	Annual Total Miles (mi/yr)	Mileage Rate (mi/gal)	Peak Daily Diesel Fuel Usage (gal/day)*	Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	360	660	6.50721657	55	101
				TOTAL	**55**	**101**

Source:
On-Road Mobile Emission Factors (EMFAC 2017), Scenario Year 2021

GHG EMISSIONS

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	0.77	MWh/day	Electricity GHGs	139.47	0.0000	0.0000	139
temporary construction activities	Add in the GHG Emissions Calculated for Construction Emissions						
operational truck trips	0.95	MT/year	Operation GHGs in CO2e				1
						TOTAL CO2e	**140**

GHGs from temporary construction activities are amortized over 30 years.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned

OPERATIONAL IMPACTS PER 1 UNIT FOR FACILITY

1 New SCR for 1 Heater/Boiler with One 11,000 gal NH3(aq) Tank

	Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Heaters/Boilers	Electricity	139,784	kWh	383	kWh
	Plot Space Needed	49.8835133	sf		
	19% Aqueous NH3 Usage at 95% Control	78,967	lb	216	lb
	19% Aqueous NH3 Usage at 95% Control	10,282	gal	28	gal
	No. of Trucks Delivering 19% Aqueous NH3	2	trucks	1	truck (fixed)
	Truck Delivering 19% Aqueous NH3	200	round trip miles	100	round trip miles
	No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck (fixed)
	Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
	No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck (fixed)
	Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles

TOTAL OPERATIONAL IMPACTS FOR FACILITY

3 New SCR for Heaters/Boilers with 11,000 gal NH3(aq) Tanks

Utility/Infrastructure	Annual Usage		Daily Usage	
Electricity	419,352	kWh	1,149	kWh
Plot Space Needed	150	sf		
19% Aqueous NH3 Usage at 95% Control	236,901	lb	649	lb
19% Aqueous NH3 Usage at 95% Control	30,846	gal	85	gal
No. of Trucks Delivering 19% Aqueous NH3	5	trucks	1	truck
Truck Delivering 19% Aqueous NH3	500	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck
Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles
Total No. of Trucks	7	trucks	2	trucks
Total Truck Miles	860	miles	360	miles

EQUIPMENT AVERAGES

Heater/Boiler with New SCR	Average Maximum Firing Rating	71.33	MMBTU/hr
	Catalyst Volume	2215.78	ft3
	Catalyst Mass	25354.6	lb

EQUATIONS

Catalyst Volume for 1 SCR for Heater/Boiler or Gas Turbine
= Average Maximum Firing Rating x 16929 / 545*

Number of NH3 Trucks = NH3 Volume in Gallons / 7000 gal per Truck
Number of Spent Catalyst Trucks
= Catalyst Volume x Catalyst Density Factor / 50000 lb Truck / 5 years
Number of Fresh Catalyst Trucks = Number of Spent Catalyst Trucks

OPERATIONS - ON-ROAD VEHICLES AND FUEL USE

Operation	Peak Daily Round-trip Distance (mi/day)	Annual Round-trip Distance (mi/yr)	Mileage Rate (mi/ gal)	2021 Mobile Source Emission Factors							
On-Road Equipment Type				VOC (lb/mi)	CO (lb/mi)	NOx (lb/mi)	SOx (lb/mi)	PM10 (lb/mi)	PM2.5 (lb/mi)	CO2 (lb/mi)	CH4 (lb/mi)
Offsite (Heavy-Heavy Duty Truck)	360	860	6.51	0.00022863	0.00095415	0.00838930	0.00003002	0.00011390	0.00010897	3.17714107	0.00001062

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	0.08	0.34	3.02	0.01	0.04	0.04	1143.77	0.00	1,144
TOTAL	**0**	**0**	**3**	**0**	**0**	**0**	**1,144**	**0**	**1,144**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	2732.34	0.01	2,733	1
TOTAL	**2,732**	**0**	**2,733**	**1**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Peak Day Total Miles (mi/day)	Annual Total Miles (mi/yr)	Mileage Rate (mi/gal)	Peak Daily Diesel Fuel Usage (gal/day)*	Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	360	860	6.50721657	55	132
				TOTAL	**55**	**132**

Source:

On-Road Mobile Emission Factors (EMFAC 2017), Scenario Year 2021

GHG EMISSIONS

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	1.15	MWh/day	Electricity GHGs	209.20	0.0000	0.0000	209
temporary construction activities	Add in the GHG Emissions Calculated for Construction Emissions						
operational truck trips	1.24	MT/year	Operation GHGs in CO2e				1
						TOTAL CO2e	**210**

GHGs from temporary construction activities are amortized over 30 years.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned

OPERATIONAL IMPACTS PER 1 UNIT FOR FACILITY

1 New SCR for 1 Heater/Boiler with One 11,000 gal NH3(aq) Tank

Heaters/Boilers

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	58,627	kWh	161	kWh
Plot Space Needed	51.86461608	sf		
19% Aqueous NH3 Usage at 95% Control	82,090	lb	225	lb
19% Aqueous NH3 Usage at 95% Control	10,689	gal	29	gal
No. of Trucks Delivering 19% Aqueous NH3	2	trucks	1	truck (fixed)
Truck Delivering 19% Aqueous NH3	200	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck (fixed)
Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck (fixed)
Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles

[Replaces pgs C-14 and C-15 of the September 2021 Draft SEA]

TOTAL OPERATIONAL IMPACTS FOR FACILITY

12 **New SCR for Heaters/Boilers with 11,000 gal NH3(aq) Tanks**

Utility/Infrastructure	Annual Usage		Daily Usage	
Electricity	703,520	kWh	1,927	kWh
Plot Space Needed	622	sf		
19% Aqueous NH3 Usage at 95% Control	985,076	lb	2,699	lb
19% Aqueous NH3 Usage at 95% Control	128,265	gal	351	gal
No. of Trucks Delivering 19% Aqueous NH3	19	trucks	1	truck
Truck Delivering 19% Aqueous NH3	1,900	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	2	trucks	1	truck
Truck Hauling Spent Catalyst (Once Every Five Years)	520	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	2	trucks	0	truck
Truck Delivering Fresh Catalyst (Once Every Five Years)	200	round trip miles	100	round trip miles
Total No. of Trucks	23	trucks	2	trucks
Total Truck Miles	2,620	miles	360	miles

EQUIPMENT AVERAGES

Heater/Boiler with New SCR	Average Maximum Firing Rating	74.17	MMBTU/hr
	Catalyst Volume	2303.79	ft3
	Catalyst Mass	26361.7	lb

EQUATIONS

Catalyst Volume for 1 SCR for Heater/Boiler or Gas Turbine
= Average Maximum Firing Rating x 16929 / 545*

Number of NH3 Trucks = NH3 Volume in Gallons / 7000 gal per Truck
Number of Spent Catalyst Trucks
= Catalyst Volume x Catalyst Density Factor / 50000 lb Truck / 5 years
Number of Fresh Catalyst Trucks = Number of Spent Catalyst Trucks

OPERATIONS - ON-ROAD VEHICLES AND FUEL USE

Operation	Peak Daily Round-trip Distance (mi/day)	Annual Round-trip Distance (mi/yr)	Mileage Rate (mi/ gal)	2021 Mobile Source Emission Factors							
On-Road Equipment Type				VOC (lb/mi)	CO (lb/mi)	NOx (lb/mi)	SOx (lb/mi)	PM10 (lb/mi)	PM2.5 (lb/mi)	CO2 (lb/mi)	CH4 (lb/mi)
Offsite (Heavy-Heavy Duty Truck)	360	2,620	6.51	0.00022863	0.00095415	0.00838930	0.00003002	0.00011390	0.00010897	3.17714107	0.00001062

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	0.08	0.34	3.02	0.01	0.04	0.04	1143.77	0.00	1,144
TOTAL	**0**	**0**	**3**	**0**	**0**	**0**	**1,144**	**0**	**1,144**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	8324.11	0.03	8,325	4
TOTAL	**8,324**	**0**	**8,325**	**4**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Peak Day Total Miles (mi/day)	Annual Total Miles (mi/yr)	Mileage Rate (mi/gal)	Peak Daily Diesel Fuel Usage (gal/day)*	Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	360	2,620	6.50721657	55	403
				TOTAL	**55**	**403**

Source:
On-Road Mobile Emission Factors (EMFAC 2017), Scenario Year 2021

GHG EMISSIONS

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	1.93	MWh/day	Electricity GHGs	350.96	0.0000	0.0000	351
temporary construction activities	Add in the GHG Emissions Calculated for Construction Emissions						
operational truck trips	3.78	MT/year	Operation GHGs in CO2e				4
						TOTAL CO2e	**355**

GHGs from temporary construction activities are amortized over 30 years.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned

Draft Subsequent Environmental Assessment
Appendix C

OPERATIONAL IMPACTS PER 1 UNIT FOR FACILITY

Heaters/Boilers

1 New SCR for 1 Heater/Boiler with One 11,000 gal NH3(aq) Tank

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	58,627	kWh	161	kWh
Plot Space Needed	51.86461608	sf		
19% Aqueous NH3 Usage at 95% Control	82,090	lb	225	lb
19% Aqueous NH3 Usage at 95% Control	10,689	gal	29	gal
No. of Trucks Delivering 19% Aqueous NH3	2	trucks	1	truck (fixed)
Truck Delivering 19% Aqueous NH3	200	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck (fixed)
Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck (fixed)
Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles

TOTAL OPERATIONAL IMPACTS FOR FACILITY

6 New SCR for Heaters/Boilers with 11,000 gal NH3(aq) Tanks

Utility/Infrastructure	Annual Usage		Daily Usage	
Electricity	351,760	kWh	964	kWh
Plot Space Needed	311	sf		
19% Aqueous NH3 Usage at 95% Control	492,538	lb	1,349	lb
19% Aqueous NH3 Usage at 95% Control	64,133	gal	176	gal
No. of Trucks Delivering 19% Aqueous NH3	10	trucks	1	truck
Truck Delivering 19% Aqueous NH3	1,000	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck
Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles
Total No. of Trucks	12	trucks	2	trucks
Total Truck Miles	1,360	miles	360	miles

EQUIPMENT AVERAGES

Heater/Boiler with New SCR	Average Maximum Firing Rating	74.17	MMBTU/hr
	Catalyst Volume	2303.79	ft3
	Catalyst Mass	26361.7	lb

EQUATIONS

Catalyst Volume for 1 SCR for Heater/Boiler or Gas Turbine
= Average Maximum Firing Rating x 16929 / 545*

Number of NH3 Trucks = NH3 Volume in Gallons / 7000 gal per Truck
Number of Spent Catalyst Trucks
= Catalyst Volume x Catalyst Density Factor / 50000 lb Truck / 5 years
Number of Fresh Catalyst Trucks = Number of Spent Catalyst Trucks

OPERATIONS - ON-ROAD VEHICLES AND FUEL USE

Operation	Peak Daily Round-trip Distance (mi/day)	Annual Round-trip Distance (mi/yr)	Mileage Rate (mi/ gal)	2021 Mobile Source Emission Factors							
On-Road Equipment Type				VOC (lb/mi)	CO (lb/mi)	NOx (lb/mi)	SOx (lb/mi)	PM10 (lb/mi)	PM2.5 (lb/mi)	CO2 (lb/mi)	CH4 (lb/mi)
Offsite (Heavy-Heavy Duty Truck)	360	1,360	6.51	0.00022863	0.00095415	0.00838930	0.00003002	0.00011390	0.00010897	3.17714107	0.00001062

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	0.08	0.34	3.02	0.01	0.04	0.04	1143.77	0.00	1,144
TOTAL	0	0	3	0	0	0	1,144	0	1,144
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	NO	NO	NO	NO	NO	NO	n/a	n/a	n/a

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	4320.91	0.01	4,321	2
TOTAL	4,321	0	4,321	2
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	n/a	n/a	n/a	n/a

1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Peak Day Total Miles (mi/day)	Annual Total Miles (mi/yr)	Mileage Rate (mi/gal)	Peak Daily Diesel Fuel Usage (gal/day)*	Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	360	1,360	6.50721657	55	209
				TOTAL	55	209

Source:
On-Road Mobile Emission Factors (EMFAC 2017), Scenario Year 2021

GHG EMISSIONS

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	0.96	MWh/day	Electricity GHGs	175.48	0.0000	0.0000	175
temporary construction activities	Add in the GHG Emissions Calculated for Construction Emissions						
operational truck trips	1.96	MT/year	Operation GHGs in CO2e				2
						TOTAL CO2e	177

GHGs from temporary construction activities are amortized over 30 years.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned

OPERATIONAL IMPACTS PER 1 UNIT FOR FACILITY

Heaters/Boilers

1 New SCR for 1 Heater/Boiler with One 11,000 gal NH3(aq) Tank

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	50,712	kWh	139	kWh
Plot Space Needed	211.3653851	sf		
19% Aqueous NH3 Usage at 95% Control	99,639	lb	273	lb
19% Aqueous NH3 Usage at 95% Control	12,974	gal	36	gal
No. of Trucks Delivering 19% Aqueous NH3	0	trucks	0	truck (fixed)
Truck Delivering 19% Aqueous NH3	0	round trip miles	0	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck (fixed)
Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck (fixed)
Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles

TOTAL OPERATIONAL IMPACTS FOR FACILITY

3 New SCR for Heaters/Boilers with 11,000 gal NH3(aq) Tanks

Utility/Infrastructure	Annual Usage		Daily Usage	
Electricity	152,136	kWh	417	kWh
Plot Space Needed	634	sf		
19% Aqueous NH3 Usage at 95% Control	298,917	lb	819	lb
19% Aqueous NH3 Usage at 95% Control	38,921	gal	107	gal
No. of Trucks Delivering 19% Aqueous NH3	0	trucks	0	truck
Truck Delivering 19% Aqueous NH3	0	round trip miles	0	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck
Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles
Total No. of Trucks	2	trucks	1	trucks
Total Truck Miles	360	miles	260	miles

EQUIPMENT AVERAGES

Heater/Boiler with New SCR	Average Maximum Firing Rating	63.67	MMBTU/hr
	Catalyst Volume	1977.64	ft3
	Catalyst Mass	22629.6	lb

EQUATIONS

Catalyst Volume for 1 SCR for Heater/Boiler or Gas Turbine
= Average Maximum Firing Rating x 16929 / 545*

Number of NH3 Trucks = NH3 Volume in Gallons / 7000 gal per Truck
Number of Spent Catalyst Trucks
= Catalyst Volume x Catalyst Density Factor / 50000 lb Truck / 5 years
Number of Fresh Catalyst Trucks = Number of Spent Catalyst Trucks

OPERATIONS - ON-ROAD VEHICLES AND FUEL USE

Operation	Peak Daily Round-trip Distance (mi/day)	Annual Round-trip Distance (mi/yr)	Mileage Rate (mi/ gal)	2021 Mobile Source Emission Factors							
On-Road Equipment Type				VOC (lb/mi)	CO (lb/mi)	NOx (lb/mi)	SOx (lb/mi)	PM10 (lb/mi)	PM2.5 (lb/mi)	CO2 (lb/mi)	CH4 (lb/mi)
Offsite (Heavy-Heavy Duty Truck)	260	360	6.51	0.00022863	0.00095415	0.00838930	0.00003002	0.00011390	0.00010897	3.17714107	0.00001062

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	0.06	0.25	2.18	0.01	0.03	0.03	826.06	0.00	826
TOTAL	**0**	**0**	**2**	**0**	**0**	**0**	**826**	**0**	**826**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	1143.77	0.00	1,144	1
TOTAL	**1,144**	**0**	**1,144**	**1**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Peak Day Total Miles (mi/day)	Annual Total Miles (mi/yr)	Mileage Rate (mi/gal)	Peak Daily Diesel Fuel Usage (gal/day)*	Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	260	360	6.50721657	40	55
				TOTAL	**40**	**55**

Source:
On-Road Mobile Emission Factors (EMFAC 2017), Scenario Year 2021

GHG EMISSIONS

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	0.42	MWh/day	Electricity GHGs	75.90	0.0000	0.0000	76
temporary construction activities	Add in the GHG Emissions Calculated for Construction Emissions						
operational truck trips	0.52	MT/year	Operation GHGs in CO2e				1
						TOTAL CO2e	**76**

GHGs from temporary construction activities are amortized over 30 years.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned

OPERATIONAL IMPACTS PER 1 UNIT FOR FACILITY

1 New SCR for 1 Heater/Boiler with One 11,000 gal NH3(aq) Tank

Heaters/Boilers

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	246,074	kWh	674	kWh
Plot Space Needed	513.5636057	sf		
19% Aqueous NH3 Usage at 95% Control	492,879	lb	1350	lb
19% Aqueous NH3 Usage at 95% Control	64,177	gal	176	gal
No. of Trucks Delivering 19% Aqueous NH3	10	trucks	1	truck (fixed)
Truck Delivering 19% Aqueous NH3	1,000	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck (fixed)
Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck (fixed)
Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles

TOTAL OPERATIONAL IMPACTS FOR FACILITY

2 New SCR for Heaters/Boilers with 11,000 gal NH3(aq) Tanks

Utility/Infrastructure	Annual Usage		Daily Usage	
Electricity	492,147	kWh	1,348	kWh
Plot Space Needed	1,027	sf		
19% Aqueous NH3 Usage at 95% Control	985,758	lb	2,701	lb
19% Aqueous NH3 Usage at 95% Control	128,354	gal	352	gal
No. of Trucks Delivering 19% Aqueous NH3	19	trucks	1	truck
Truck Delivering 19% Aqueous NH3	1,900	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck
Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles
Total No. of Trucks	21	trucks	2	trucks
Total Truck Miles	2,260	miles	360	miles

EQUIPMENT AVERAGES

Heater/Boiler with New SCR	Average Maximum Firing Rating	317.50	MMBTU/hr
	Catalyst Volume	9862.31	ft3
	Catalyst Mass	112852	lb

EQUATIONS

Catalyst Volume for 1 SCR for Heater/Boiler or Gas Turbine
= Average Maximum Firing Rating x 16929 / 545*

Number of NH3 Trucks = NH3 Volume in Gallons / 7000 gal per Truck
Number of Spent Catalyst Trucks
= Catalyst Volume x Catalyst Density Factor / 50000 lb Truck / 5 years
Number of Fresh Catalyst Trucks = Number of Spent Catalyst Trucks

OPERATIONS - ON-ROAD VEHICLES AND FUEL USE

Operation	Peak Daily Round-trip Distance (mi/day)	Annual Round-trip Distance (mi/yr)	Mileage Rate (mi/ gal)	2021 Mobile Source Emission Factors							
On-Road Equipment Type				VOC (lb/mi)	CO (lb/mi)	NOx (lb/mi)	SOx (lb/mi)	PM10 (lb/mi)	PM2.5 (lb/mi)	CO2 (lb/mi)	CH4 (lb/mi)
Offsite (Heavy-Heavy Duty Truck)	360	2,260	6.51	0.00022863	0.00095415	0.00838930	0.00003002	0.00011390	0.00010897	3.17714107	0.00001062

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	0.08	0.34	3.02	0.01	0.04	0.04	1143.77	0.00	1,144
TOTAL	**0**	**0**	**3**	**0**	**0**	**0**	**1,144**	**0**	**1,144**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	7180.34	0.02	7,181	3
TOTAL	**7,180**	**0**	**7,181**	**3**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Peak Day Total Miles (mi/day)	Annual Total Miles (mi/yr)	Mileage Rate (mi/gal)	Peak Daily Diesel Fuel Usage (gal/day)*	Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	360	2,260	6.50721657	55	347
				TOTAL	**55**	**347**

Source:
On-Road Mobile Emission Factors (EMFAC 2017), Scenario Year 2021

GHG EMISSIONS

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	1.35	MWh/day	Electricity GHGs	245.52	0.0000	0.0000	246
temporary construction activities	Add in the GHG Emissions Calculated for Construction Emissions						
operational truck trips	3.26	MT/year	Operation GHGs in CO2e				3
						TOTAL CO2e	**249**

GHGs from temporary construction activities are amortized over 30 years.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned

OPERATIONAL IMPACTS PER 1 UNIT FOR FACILITY

1 New SCR for 1 Heater/Boiler with One 11,000 gal NH3(aq) Tank

Heaters/Boilers

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	101,873	kWh	279	kWh
Plot Space Needed	285.0533439	sf		
19% Aqueous NH3 Usage at 95% Control	201,932	lb	553	lb
19% Aqueous NH3 Usage at 95% Control	26,293	gal	72	gal
No. of Trucks Delivering 19% Aqueous NH3	4	trucks	1	truck (fixed)
Truck Delivering 19% Aqueous NH3	400	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck (fixed)
Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck (fixed)
Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles

TOTAL OPERATIONAL IMPACTS FOR FACILITY

2 New SCR for Heaters/Boilers with 11,000 gal NH3(aq) Tanks

Utility/Infrastructure	Annual Usage		Daily Usage	
Electricity	203,747	kWh	558	kWh
Plot Space Needed	570	sf		
19% Aqueous NH3 Usage at 95% Control	403,864	lb	1,106	lb
19% Aqueous NH3 Usage at 95% Control	52,586	gal	144	gal
No. of Trucks Delivering 19% Aqueous NH3	8	trucks	1	truck
Truck Delivering 19% Aqueous NH3	800	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck
Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles
Total No. of Trucks	10	trucks	2	trucks
Total Truck Miles	1,160	miles	360	miles

EQUIPMENT AVERAGES

Heater/Boiler with New SCR	Average Maximum Firing Rating	129.00	MMBTU/hr
	Catalyst Volume	4007.05	ft3
	Catalyst Mass	45851.5	lb

EQUATIONS

Catalyst Volume for 1 SCR for Heater/Boiler or Gas Turbine
= Average Maximum Firing Rating x 16929 / 545*

Number of NH3 Trucks = NH3 Volume in Gallons / 7000 gal per Truck
Number of Spent Catalyst Trucks
= Catalyst Volume x Catalyst Density Factor / 50000 lb Truck / 5 years
Number of Fresh Catalyst Trucks = Number of Spent Catalyst Trucks

OPERATIONS - ON-ROAD VEHICLES AND FUEL USE

Operation	Peak Daily Round-trip Distance (mi/day)	Annual Round-trip Distance (mi/yr)	Mileage Rate (mi/ gal)	2021 Mobile Source Emission Factors							
On-Road Equipment Type				VOC (lb/mi)	CO (lb/mi)	NOx (lb/mi)	SOx (lb/mi)	PM10 (lb/mi)	PM2.5 (lb/mi)	CO2 (lb/mi)	CH4 (lb/mi)
Offsite (Heavy-Heavy Duty Truck)	360	1,160	6.51	0.00022863	0.00095415	0.00838930	0.00003002	0.00011390	0.00010897	3.17714107	0.00001062

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	0.08	0.34	3.02	0.01	0.04	0.04	1143.77	0.00	1,144
TOTAL	**0**	**0**	**3**	**0**	**0**	**0**	**1,144**	**0**	**1,144**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	3685.48	0.01	3,686	2
TOTAL	**3,685**	**0**	**3,686**	**2**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Peak Day Total Miles (mi/day)	Annual Total Miles (mi/yr)	Mileage Rate (mi/gal)	Peak Daily Diesel Fuel Usage (gal/day)*	Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	360	1,160	6.50721657	55	178
				TOTAL	**55**	**178**

Source:
On-Road Mobile Emission Factors (EMFAC 2017), Scenario Year 2021

GHG EMISSIONS

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	0.56	MWh/day	Electricity GHGs	101.64	0.0000	0.0000	102
temporary construction activities	Add in the GHG Emissions Calculated for Construction Emissions						
operational truck trips	1.67	MT/year	Operation GHGs in CO2e				2
						TOTAL CO2e	**103**

GHGs from temporary construction activities are amortized over 30 years.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned

OPERATIONAL IMPACTS PER 1 UNIT FOR FACILITY

1 New SCR for 1 Heater/Boiler with One 11,000 gal NH3(aq) Tank

Heaters/Boilers

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	122,243	kWh	335	kWh
Plot Space Needed	425.1885434	sf		
19% Aqueous NH3 Usage at 95% Control	242,999	lb	666	lb
19% Aqueous NH3 Usage at 95% Control	31,641	gal	87	gal
No. of Trucks Delivering 19% Aqueous NH3	5	trucks	1	truck (fixed)
Truck Delivering 19% Aqueous NH3	500	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck (fixed)
Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck (fixed)
Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles

TOTAL OPERATIONAL IMPACTS FOR FACILITY

3 New SCR for Heaters/Boilers with 11,000 gal NH3(aq) Tanks

Utility/Infrastructure	Annual Usage		Daily Usage	
Electricity	366,728	kWh	1,005	kWh
Plot Space Needed	1,276	sf		
19% Aqueous NH3 Usage at 95% Control	728,998	lb	1,997	lb
19% Aqueous NH3 Usage at 95% Control	94,922	gal	260	gal
No. of Trucks Delivering 19% Aqueous NH3	14	trucks	1	truck
Truck Delivering 19% Aqueous NH3	1,400	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck
Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles
Total No. of Trucks	16	trucks	2	trucks
Total Truck Miles	1,760	miles	360	miles

EQUIPMENT AVERAGES

Heater/Boiler with New SCR	Average Maximum Firing Rating	155.33	MMBTU/hr
	Catalyst Volume	4825.02	ft3
	Catalyst Mass	55211.4	lb

EQUATIONS

Catalyst Volume for 1 SCR for Heater/Boiler or Gas Turbine
= Average Maximum Firing Rating x 16929 / 545*

Number of NH3 Trucks = NH3 Volume in Gallons / 7000 gal per Truck
Number of Spent Catalyst Trucks
= Catalyst Volume x Catalyst Density Factor / 50000 lb Truck / 5 years
Number of Fresh Catalyst Trucks = Number of Spent Catalyst Trucks

OPERATIONS - ON-ROAD VEHICLES AND FUEL USE

Operation	Peak Daily Round-trip Distance (mi/day)	Annual Round-trip Distance (mi/yr)	Mileage Rate (mi/ gal)	2021 Mobile Source Emission Factors							
On-Road Equipment Type				VOC (lb/mi)	CO (lb/mi)	NOx (lb/mi)	SOx (lb/mi)	PM10 (lb/mi)	PM2.5 (lb/mi)	CO2 (lb/mi)	CH4 (lb/mi)
Offsite (Heavy-Heavy Duty Truck)	360	1,760	6.51	0.00022863	0.00095415	0.00838930	0.00003002	0.00011390	0.00010897	3.17714107	0.00001062

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	0.08	0.34	3.02	0.01	0.04	0.04	1143.77	0.00	1,144
TOTAL	**0**	**0**	**3**	**0**	**0**	**0**	**1,144**	**0**	**1,144**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	5591.77	0.02	5,592	3
TOTAL	**5,592**	**0**	**5,592**	**3**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Peak Day Total Miles (mi/day)	Annual Total Miles (mi/yr)	Mileage Rate (mi/gal)	Peak Daily Diesel Fuel Usage (gal/day)*	Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	360	1,760	6.50721657	55	270
				TOTAL	**55**	**270**

Source:
On-Road Mobile Emission Factors (EMFAC 2017), Scenario Year 2021

GHG EMISSIONS

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	1.00	MWh/day	Electricity GHGs	182.95	0.0000	0.0000	183
temporary construction activities	Add in the GHG Emissions Calculated for Construction Emissions						
operational truck trips	2.54	MT/year	Operation GHGs in CO2e				3
						TOTAL CO2e	**185**

GHGs from temporary construction activities are amortized over 30 years.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned

OPERATIONAL IMPACTS PER 1 UNIT FOR FACILITY

1 New SCR for 1 Heater/Boiler with One 11,000 gal NH3(aq) Tank

Heaters/Boilers

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	88,181	kWh	242	kWh
Plot Space Needed	31.46857147	sf		
19% Aqueous NH3 Usage at 95% Control	49,816	lb	136	lb
19% Aqueous NH3 Usage at 95% Control	6,486	gal	18	gal
No. of Trucks Delivering 19% Aqueous NH3	1	trucks	1	truck (fixed)
Truck Delivering 19% Aqueous NH3	100	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck (fixed)
Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck (fixed)
Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles

TOTAL OPERATIONAL IMPACTS FOR FACILITY

1 New SCR for Heaters/Boilers with 11,000 gal NH3(aq) Tanks

Utility/Infrastructure	Annual Usage		Daily Usage	
Electricity	88,181	kWh	242	kWh
Plot Space Needed	31	sf		
19% Aqueous NH3 Usage at 95% Control	49,816	lb	136	lb
19% Aqueous NH3 Usage at 95% Control	6,486	gal	18	gal
No. of Trucks Delivering 19% Aqueous NH3	1	trucks	1	truck
Truck Delivering 19% Aqueous NH3	100	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
Truck Hauling Spent Catalyst (Once Every Five Years)	260	round trip miles	260	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	0	truck
Truck Delivering Fresh Catalyst (Once Every Five Years)	100	round trip miles	100	round trip miles
Total No. of Trucks	3	trucks	2	trucks
Total Truck Miles	460	miles	360	miles

EQUIPMENT AVERAGES

Heater/Boiler with New SCR	Average Maximum Firing Rating	45.00	MMBTU/hr
	Catalyst Volume	1397.81	ft3
	Catalyst Mass	15994.7	lb

EQUATIONS

Catalyst Volume for 1 SCR for Heater/Boiler or Gas Turbine
= Average Maximum Firing Rating x 16929 / 545*

Number of NH3 Trucks = NH3 Volume in Gallons / 7000 gal per Truck
Number of Spent Catalyst Trucks
= Catalyst Volume x Catalyst Density Factor / 50000 lb Truck / 5 years
Number of Fresh Catalyst Trucks = Number of Spent Catalyst Trucks

OPERATIONS - ON-ROAD VEHICLES AND FUEL USE

Operation	Peak Daily Round-trip Distance (mi/day)	Annual Round-trip Distance (mi/yr)	Mileage Rate (mi/ gal)	2021 Mobile Source Emission Factors							
On-Road Equipment Type				VOC (lb/mi)	CO (lb/mi)	NOx (lb/mi)	SOx (lb/mi)	PM10 (lb/mi)	PM2.5 (lb/mi)	CO2 (lb/mi)	CH4 (lb/mi)
Offsite (Heavy-Heavy Duty Truck)	360	460	6.51	0.00022863	0.00095415	0.00838930	0.00003002	0.00011390	0.00010897	3.17714107	0.00001062

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	0.08	0.34	3.02	0.01	0.04	0.04	1143.77	0.00	1,144
TOTAL	**0**	**0**	**3**	**0**	**0**	**0**	**1,144**	**0**	**1,144**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	1461.48	0.00	1,462	1
TOTAL	**1,461**	**0**	**1,462**	**1**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Peak Day Total Miles (mi/day)	Annual Total Miles (mi/yr)	Mileage Rate (mi/gal)	Peak Daily Diesel Fuel Usage (gal/day)*	Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	360	460	6.50721657	55	71
				TOTAL	**55**	**71**

Source:
On-Road Mobile Emission Factors (EMFAC 2017), Scenario Year 2021

GHG EMISSIONS

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	0.24	MWh/day	Electricity GHGs	43.99	0.0000	0.0000	44
temporary construction activities	Add in the GHG Emissions Calculated for Construction Emissions						
operational truck trips	0.66	MT/year	Operation GHGs in CO2e				1
						TOTAL CO2e	**45**

GHGs from temporary construction activities are amortized over 30 years.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned

Peak Operational Truck Trips per Year at One Facility

EF, g/hr	Annual No of Trips	Idling, h/y	Emisions, lb/yr	Emisions, ton/yr
0.05	21	1.75	0.00	8.74E-08

Refer to EMFAC2017 Emission Rates sheet for EF

Cancer Potency Factor, (mg/kg-d)-1	Emisions, ton/yr	X/Q at 25 m, (ug/m3)/ (ton/yr)	MWAF	CEF	MP	Carcinogenic Health Risk	Screening Level	Significant?
1.1	8.74E-08	23.01	1	677.4	1	1.50E-09	1.00E-05	NO

Carcinogenic health risk = emissions, ton/yr x cancer potency, (mg/kg-day)-1 x X/Q, (ug/m3)/(ton/yr) x CEF x MP x MWHF

APPENDIX D

List of Affected Facilities and Equipment

LIST OF AFFECTED FACILITIES - PR 1109.1

FACILITY ID	FACILITY NAME IN SOUTH COAST AQMD DATABASE	ADDRESS	On DTSC List per Government Code 65962.5 (Envirostor)?	Nearest Sensitive Receptor (Miles)	Located within 1/4 Mile of a School?	Located within Two Miles of an Airport?
3417	AIR PROD & CHEM INC	23300 S. ALAMEDA ST, CARSON, CA 90810	NO	0.48	NO	NO
101656	AIR PRODUCTS AND CHEMICALS, INC.	700 N. HENRY FORD AVE, WILMINGTON, CA 90744	NO	0.28	NO	NO
148236	AIR LIQUIDE LARGE INDUSTRIES U.S., LP	324 W. EL SEGUNDO BLVD, EL SEGUNDO, CA 90245**	YES	0.03	YES	YES
151798	TESORO REFINING AND MARKETING CO, LLC	23208 S ALAMEDA ST, CARSON, CA 90810	YES	0.48	NO	NO
171107	PHILLIPS 66 CO/LA REFINERY WILMINGTON PL	1660 W ANAHEIM ST, WILMINGTON, CA 90744	YES	0.00	YES	NO
171109	PHILLIPS 66 COMPANY/LOS ANGELES REFINERY	1520 E SEPULVEDA BLVD, CARSON, CA 90745	YES	0.04	NO	NO
174591	TESORO REF & MKTG CO LLC, CALCINER	1175 CARRACK AVE, WILMINGTON, CA 90748	NO	0.93	NO	NO
174655	TESORO REFINING & MARKETING CO, LLC	2350 E 223RD ST, CARSON, CA 90810	NO	0.04	NO	NO
180908	ECO SERVICES OPERATIONS LLC	20720 S. WILMINGTON AVE, CARSON, CA 90810	YES	0.16	NO	NO
181667	TORRANCE REFINING COMPANY LLC	3700 W 190TH ST, TORRANCE, CA 90504	YES	0.01	NO	NO
187165	ALTAIR PARAMOUNT	14700 DOWNEY AVE, PARAMOUNT, CA 90723	NO	0.00	YES	NO
800026	ULTRAMAR INC	2402 E ANAHEIM ST, WILMINGTON, CA 90744	YES	0.45	NO	NO
800030	CHEVRON PRODUCTS CO.	324 W EL SEGUNDO BLVD, EL SEGUNDO, CA 90245**	YES	0.03	YES	YES
800080	LUNDAY-THAGARD CO DBA WORLD OIL REFINING	9301 GARFIELD AVE, SOUTH GATE, CA 90280	NO	0.09	NO	NO
800393	VALERO WILMINGTON ASPHALT PLANT	1651 ALAMEDA ST, WILMINGTON, CA 90744	YES	0.16	NO	NO
800436	TESORO REFINING AND MARKETING CO, LLC	2101 E PACIFIC COAST HWY, WILMINGTON, CA 90744	YES	0.18	NO	NO

CHEVRON				
Device ID	Category	Size (MMBtu/hr)	Table 1 NOx Limit	Table 2 NOx Limit
D641	Heater	365	5	22.0
D643	Heater	220	5	22.0
D451	Heater	102	5	18.0
D3053	Gas Turbine	506	2	2.5
V-10	FCCU		2	8.0
D2198	Gas Turbine	560	3	N/A
D20	Heater	217	5	22.0
D625	Heater	63	5	18.0
D617	Heater	57	5	18.0
D623	Heater	63	5	18.0
D2207	Gas Turbine	560	3	N/A
D502	Heater	70	5	18.0
D619	Heater	57	5	18.0
D504	Heater	77	5	18.0
D618	Heater	57	5	18.0
D620	Heater	57	5	18.0
D2216	Boiler	342	5	7.5
D82	Heater	315	5	22.0
D83	Heater	315	5	22.0
D84	Heater	219	5	22.0
D159	Heater	176	5	22.0
D160	Heater	176	5	22.0
D161	Heater	176	5	22.0
D955	Sulfur Recovery Unit	58	30	N/A
D927	Sulfur Recovery Unit	30	30	N/A
D466	Heater	33	40	N/A
D911	Sulfur Recovery Unit	30	30	N/A
D390	Heater	31	40	N/A
D453	Heater	44	5	18.0
C3493	Thermal Oxidizer	3	30	40.0
D1910	Heater	37	40	N/A
D398	Heater	19	40	N/A
C2158	Thermal Oxidizer	3	30	40.0
D428	Heater	36	40	N/A
D364	Heater	26	40	N/A
C3806	Thermal Oxidizer	2	30	40.0
D3778	Heater	78	5	18.0
D3695	Heater	83	5	18.0
D473	Heater	88	5	18.0
D472	Heater	123	5	22.0
D471	Heater	177	5	22.0
D3031	Heater	199	5	22.0
D3530	SMR Heater	653	5	7.5
D4354	Gas Turbine	509	2	2.5
C4344	Sulfur Recovery Unit	50	30	N/A
FACILITY TOTAL		**7063**		

PHILLIPS 66					
Device ID	Facility	Category	Size (MMBtu/hr)	Table 1 NOx Limit	Table 2 NOx Limit
D688	Wilmington	Boiler	250	5	7.5
D154	Wilmington	Heater	110	5	18.0
D155	Wilmington	Heater	100	5	18.0
D156	Wilmington	Heater	70	5	18.0
D157	Wilmington	Heater	42	5	18.0
D158	Wilmington	Heater	24	5	18.0
Regenerator	Wilmington	FCCU	-	2	8.0
D687	Wilmington	Boiler	179	5	7.5
D135	Wilmington	Heater	116	5	22.0
D136	Wilmington	Heater	68	5	22.0
D137	Wilmington	Heater	71	5	22.0
D138	Wilmington	Heater	56	5	22.0
D139	Wilmington	Heater	19	5	22.0
D684	Wilmington	Boiler	304	5	7.5
D828	Wilmington	GG-101	646	3	N/A
D264	Wilmington	Heater	135	5	22.0
D194	Wilmington	Heater	60	5	18.0
D146	Wilmington	Heater	76	5	18.0
D686	Wilmington	Boiler	304	5	7.5
D220	Wilmington	SMR Heater	350	5	7.5
D333	Wilmington	Sulfuric Acid Furnace	74	30	N/A
D262	Wilmington	Heater	37	40	N/A
D148	Wilmington	Heater	27	40	N/A
D259	Wilmington	Heater	39	40	N/A
D152	Wilmington	Heater	30	40	N/A
D150	Wilmington	Heater	38	40	N/A
D133	Wilmington	Heater	35	40	N/A
D161	Wilmington	Heater	31	40	N/A
D39	Wilmington	Heater	29	40	N/A
D329	Wilmington	Heater	29	40	N/A
D142	Wilmington	Heater	17	40	N/A
D129	Wilmington	Heater	27	40	N/A
D163	Wilmington	Heater	14	40	N/A
D260	Wilmington	Heater	17	40	N/A
D40	Wilmington	Heater	10	40	N/A
D1720	Wilmington	Heater	41	5	18.0
D332	Wilmington	Sulfuric Acid Furnace	15	30	N/A
D1349	Wilmington	SMR Heater	460	5	7.5
C436	Wilmington	Sulfur Recovery Unit	20	30	N/A
C456	Wilmington	Sulfur Recovery Unit	20	30	N/A
D430	Carson	Boiler	352	5	7.5
D210	Carson	SMR Heater	340	5	7.5
D59	Carson	Heater	350	5	22.0
D174	Carson	Heater	70	5	18.0
D105	Carson	Heater	175	5	22.0
D104	Carson	Heater	175	5	22.0
D79	Carson	Heater	154	5	22.0
D78	Carson	Heater	154	5	22.0
D429	Carson	Boiler	352	5	7.5
D713	Carson	Heater	22	40	N/A
C292	Carson	Sulfur Recovery Unit	15	30	N/A
C294	Carson	Sulfur Recovery Unit	28	30	N/A
FACILITY TOTAL			**3,989**		

TESORO

Device ID	Facility	Category	Size (MMBtu/hr)	Table 1 NOx Limit	Table 2 NOx Limit
D27	Carson	Heater	550	5	22
D20	Carson	Coke Calciner	120	5	N/A
D570	Carson	SMR Heater	650	5	7.5
D629	Carson	Heater	173	5	22
D535	Carson	Heater	310	5	22
D532	Carson	Heater	255	5	22
D31	Carson	Heater	130	5	22
D151	Carson	Heater	130	5	22
D155	Carson	Heater	130	5	22
D423	Carson	Heater	80	5	18
D153	Carson	Heater	130	5	22
D67	Carson	Heater	120	5	22
D29	Carson	Heater	150	5	22
D33	Carson	Heater	100	5	18
D539	Carson	Heater	52	5	18
D421	Carson	Heater	82	5	18
D625	Carson	Heater	39	40	N/A
C54	Carson	Sulfur Recovery Unit	52	30	N/A
D250	Carson	Heater	89	5	18
C910	Carson	Sulfur Recovery Unit	45	30	N/A
C2413	Carson	Sulfur Recovery Unit	40	30	N/A
D538	Carson	Heater	39	40	N/A
D416	Carson	Heater	24	40	N/A
D626	Carson	Heater	39	40	N/A
D628	Carson	Heater	39	40	N/A
D63	Carson	Heater	300	5	22
D541	Carson	Heater	39	40	N/A
D1465	Carson	SMR Heater	427	5	7.5
D627	Carson	Heater	39	40	N/A
C56	Carson	Sulfur Recovery Unit	45	30	N/A
D419	Carson	Heater	52	5	18
D425	Carson	Heater	22	40	N/A
D1433	Carson	Heater	13	40	N/A
D418	Carson	Heater	11	40	N/A
D417	Carson	Heater	10	40	N/A
D1233	Carson	Cogen Turbine U92	986	3	N/A
D1239	Carson	Cogen Turbine U94	986	3	N/A
D1226	Carson	Cogen Turbine U91	986	3	N/A
D1236	Carson	Cogen Turbine U93	986	3	N/A
D164	Carson	FCCU		2	8.0
D96	Wilmington	FCCU		2	8.0
D724	Wilmington	Boiler	184	5	7.5
D722	Wilmington	Boiler	184	5	7.5
D76/D77 (SRP)	Wilmington	Boiler	112	5	7.5
D812	Wilmington	COGEN B	392	3	N/A
D810	Wilmington	COGEN A	392	3	N/A
D32	Wilmington	Heater	218	5	22

D89	Wilmington	Heater	95	5	18
D9	Wilmington	Heater	200	5	22
D247	Wilmington	Heater	82	5	18
D248	Wilmington	Heater	50	5	18
D249	Wilmington	Heater	29	5	18
D90	Wilmington	Heater	127	5	22
D146	Wilmington	Heater	69	5	18
D33	Wilmington	Heater	252	5	22
D388	Wilmington	Heater	147	5	22
D214	Wilmington	Heater	56	5	18
D215	Wilmington	Heater	36	5	18
D216	Wilmington	Heater	31	5	18
D217	Wilmington	Heater	31	5	18
D158	Wilmington	Heater	204	5	22
D386	Wilmington	Heater	48	5	18
D387	Wilmington	Heater	71	5	18
D120	Wilmington	Heater	45	5	18
D157	Wilmington	Heater	49	5	18
D218	Wilmington	Heater	60	5	18
D92	Wilmington	Heater	37	40	18
D384	Wilmington	Heater	48	5	18
D385	Wilmington	Heater	24	5	18
D1122	Wilmington	Boiler	140	5.0	7.5
D777	Wilmington	SMR Heater	146	5.0	7.5
D250	Wilmington	Heater	35	40	N/A
D770	Wilmington	Heater	63	5	18
D723	Wilmington	Boiler	184	5	7.5
D725	Wilmington	Boiler	184	5	7.5
FACILITY TOTAL					

TORRANCE				
Device ID	Category	Size (MMBtu/hr)	Table 1 NOx Limit	Table 2 NOx Limit
D803	Boiler	309	5	7.5
D805	Boiler	291	5	7.5
D367	SMR Heater	527	5	7.5
2C-3	FCCU		2	8.0
D913	Heater	457	5	22.0
D914	Heater	161	5	22.0
D917	Heater	91	5	18.0
D918	Heater	91	5	18.0
D120	Heater	126	5	22.0
D930	Heater	129	5	22.0
D83	Heater	67	5	18.0
D84	Heater	67	5	18.0
D85	Heater	74	5	18.0
D931	Heater	73	5	18.0
D269	Heater	107	5	18.0
D920	Heater	108	5	18.0
D1239	Boiler	340	5	7.5
D1236	Boiler	340	5	7.5
C626	Thermal Oxidizer	60	30	40.0
D949	Heater	40	40	N/A
D234	Heater	60	5	18.0
D235	Heater	60	5	18.0
D950	Heater	64	5	18.0
C686	Thermal Oxidizer	4	30	40.0
D927	Heater	17	40	N/A
D231	Heater	60	5	18.0
D232	Heater	60	5	18.0
D928	Heater	17	40	N/A
D929	Heater	21	40	N/A
D1403	Heater	21	40	N/A
C687	Thermal Oxidizer	4	30	40.0
D925/D926	SMR Heater/GTG	1247	5	7.5
C952	Sulfur Recovery Unit	100	30	40.0
FACILITY TOTAL		**5193**		

ULTRAMAR				
Device ID	Category	Size (MMBtu/hr)	Table 1 NOx Limit	Table 2 NOx Limit
D36	FCCU		2	8.0
D74	Heater	258	5	22.0
D3	Heater	159	5	22.0
D6	Heater	136	5	22.0
D52	Heater	36	40	N/A
D22	Heater	95	5	18.0
D12	Heater	144	5	22.0
D53	Heater	68	5	18.0
D8	Heater	49	5	18.0
D98	Heater	57	5	18.0
D768	Heater	110	5	18.0
D1550	Boiler	245	5	7.5
D73	Heater	30	40	N/A
D59	Heater	26	40	N/A
D60	Heater	30	40	N/A
D429	Heater	30	5	22.0
D430	Heater	200	5	22.0
D9	Heater	20	40	N/A
D378	Boiler	128	5	7.5
C1260	Sulfur Recovery Unit	36	30	40.0
D377	Boiler	39	5	7.5
D1669	Gas Turbine	342	2	2.5
FACILITY TOTAL		**2,238**		

ALTAIR				
Device ID	Category	Size (MMBtu/hr)	Table 1 NOx Limit	Table 2 NOx Limit
D128	Heater	7	40	N/A
D129	Heater	7	40	N/A
D125	Heater	11	40	N/A
D123	Heater	14	40	N/A
D124	Heater	14	40	N/A
D127	Heater	14	40	N/A
D126	Heater	17	40	N/A
D28	Heater	21	40	N/A
D48	Heater	28	40	N/A
D44	Heater	13	40	N/A
D45	Heater	22	40	N/A
D46	Heater	28	40	N/A
D26	Heater	30	40	N/A
D47	Heater	30	40	N/A
D27	Heater	35	40	N/A
D31	Heater	40	40	N/A
D73	Heater	48	5	18.0
D74	Heater	48	5	18.0
D75	Heater	38	40	N/A
D76	Heater	28	40	N/A
D29	Heater	85	5	18.0
D30	Heater	85	5	18.0
D374	Boiler	45	5	7.5
D375	Boiler	45	5	7.5
D376	Boiler	66	5	7.5
C175	Sulfur Recovery Unit	10	30	N/A
C882	Thermal Oxidizer	6	30	40.0
C887	Thermal Oxidizer	4	30	40.0
C531	Thermal Oxidizer	30	30	40.0
D569	Thermal Oxidizer	8	30	40.0
FACILITY TOTAL		**875**		

OTHER FACILITIES					
Facility	Device ID	Category	Size (MMBtu/hr)	Table 1 NOx Limit	Table 2 NOx Limit
LUNDAY-THAGARD	D84	Heater	7	40	N/A
LUNDAY-THAGARD	D19	Heater	7	40	N/A
LUNDAY-THAGARD	D20	Heater	11	40	N/A
R PRODUCTS WILMINGTO	D38	SMR Heater	14	5	7.5
AIR PRODUCTS CARSON	D30	SMR Heater	14	5	7.5
AIR LIQUIDE	D24	SMR Heater	14	5	7.5
LUNDAY-THAGARD	D214	Boiler	17	40	N/A
LUNDAY-THAGARD	D231	Boiler	21	40	N/A
ECOSERVICES	D139	Sulfuric Acid Plant	28	30	N/A
ECOSERVICES	D98	Sulfuric Acid Plant	13	30	N/A
ECOSERVICES	D1	Sulfuric Acid Plant	22	30	N/A
LUNDAY-THAGARD	C97	Thermal Oxidizer	28	30	40.0
LUNDAY-THAGARD	C105	Thermal Oxidizer	30	30	40.0
ECOSERVICES		Ground Flare	30	20	N/A
	FACILITY TOTAL		**255**		

APPENDIX E

Off-site Consequence, Ammonia Slip, and PM2.5 Concentration Analyses

Updates were made to the Ammonia Slip and PM2.5 Concentration analyses originally conducted for the Draft SEA to include equipment replacement projects. Appendix E had no page numbering in the Draft SEA; the original pages have been included in this appendix as pgs. E-23 to E-44.

Comparison of Ammonia Slip Analyses in December 2015 Final PEA for NOx RECLAIM with PR 1109.1

December 2015 Final PEA for NOx RECLAIM	Ammonia Slip Estimate from December 2015 (tons/day)	Updated Ammonia Slip Estimate to remove shutdown equipment (tons/day)*	NOx RTCs Reductions (Weighted) Claimed in December 2015 Final PEA for NOx RECLAIM (tons/day)[see Table U.2 Final Staff Report for NOx RECLAIM p. 208)	Actual NOx Emission Reductions from Off-Ramping NOx RECLAIM to Command-and-Control (tons/day)	Annual PM2.5 Emission Reductions from RTC Reductions per December 2015 NOx RECLAIM (micrograms/cubic meter)	Concurrent Increase in Annual PM2.5 Emissions from Ammonia Slip Usage per December 2015 NOx RECLAIM (micrograms/cubic meter)	Net Benefit of Annual PM2.5 Reductions from December 2015 NOx RECLAIM
Non-Refinery Facilities	0.213	0.213	4.42	5.05^			
Refinery Facilities (1 through 9)	1.415	1.400	9.58	8.95#	0.7	0.6	0.1
Total	**1.63**	**1.62**	**14**	**14**			

* removes facility 4 fccu nh3 slip due to shutdown of fccu which represents 0.17 ton/day NOx reductions

^See below other off-ramp Rules analysis; # amount remaining needed by PR 1109.1

PR 1109.1: Same Refinery Facilities Evaluated in December 2015 Final PEA for NOx RECLAIM (1 through 9) plus additional facilities 11-14~	Ammonia Slip (tons/day)	NOx Emission Reductions for PR 1109.1 (tons/day)
Only equipment utlizing ammonia subject to PR 1109.1 but that were not previously analyzed in December 2015 Final PEA for NOx RECLAIM, but the NH3 slip for NOx RECLAIM was overestimated	0.072	
All PR 1109.1 Equipment Utilizing Ammonia (corresponds to Refinery Facilities category December 2015 Final PEA for NOx RECLAIM)	**0.647**	**7**

This is less than refinery portion of NOx RECLAIM and less than entire ammonia slip portion for both refinery and non-refinery facilities combined

This Updated Ammonia Slip Analysis Replaces the Previous Appendix E of the September 2021 Draft SEA

NOx RECLAIM Off-Ramp Rule Amendments for Non-Refinery Facilities	Date of Amendment	NOx Emission Reductions from Off-Ramp Rules for Non-Refinery Facilities (tons/day)
1135	11/2/2018	1.7
1146, 1146.1, & 1146.2	12/7/2018	0.27
1134	4/5/2019	2.8
1110.2	11/1/2019	0.28
	total	**5.05**

For Cells B13 through B15, Stack Pollutant Concentration x (20.9/(20.9-O2 Concentration))
http://www.aqmd.gov/docs/default-source/laboratory-procedures/methods-procedures/higho2protoco.pdf

Stack Pollutant Concentration = (5*17*8710)/(385*1000000)
http://www.aqmd.gov/docs/default-source/permitting/boiler_template.pdf
5ppm Ammonia Slip Limit
17 = NH3 Molecular Weight
8710 dscf per MMBTU for Natural Gas F-factor
385 ft3/lb-mol Molar Volume
1000000 BTU per MMBTU

Stack Correction	lb/MMBTU NH3	Equipment Type
At 0% O2	0.001922987	FCCU
At 3% O2	0.002245275	All Other Equipment
At 15% O2	0.006811937	Gas Turbines

per Sarady's Email on 2/17/21

Below lists all equipment in the 1109.1 universe which has existing SCR, is assumed to install SCR, or has an existing SCR that will be upgraded. Equipment has not been double-counted.

Facilities Subject to PR 1109.1

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
1	52	0.117	Heater
1	52	0.117	Heater
1	80	0.180	Heater
1	82	0.184	Heater
1	89	0.200	Heater
1	100	0.225	Heater
1	120	0.269	Heater
1	130	0.292	Heater
1	130	0.292	Heater
1	130	0.292	Heater
1	130	0.292	Heater
1	150	0.337	Heater
1	173	0.388	Heater

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
1	255	0.573	Heater
1	300	0.674	Heater
1	310	0.696	Heater
1	550	1.235	Heater
1	427	0.959	SMR Heater
1	650	1.459	SMR Heater
3	112	0.252	Boiler
3	112	0.252	Boiler
4	24	0.053	Heater
4	29	0.064	Heater
4	31	0.071	Heater
4	31	0.071	Heater
4	36	0.081	Heater
4	45	0.101	Heater
4	48	0.107	Heater
4	48	0.107	Heater
4	49	0.109	Heater
4	50	0.112	Heater
4	56	0.125	Heater
4	60	0.135	Heater
4	63	0.142	Heater
4	69	0.155	Heater
4	71	0.160	Heater
4	82	0.185	Heater
4	147	0.330	Heater
4	199	0.447	Heater
4	204	0.458	Heater
4	218	0.490	Heater
4	252	0.566	Heater
4	145.97	0.328	SMR Heater
4	139.5	0.313	Boiler
4	183.54	0.412	Boiler

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
4	183.54	0.412	Boiler
4	183.54	0.412	Boiler
4	183.54	0.412	Boiler
5	33.4	0.075	Heater
5	33.4	0.075	Heater
5	44	0.099	Heater
5	57	0.128	Heater
5	57	0.128	Heater
5	57	0.128	Heater
5	57	0.128	Heater
5	63	0.141	Heater
5	63	0.141	Heater
5	70	0.157	Heater
5	77	0.173	Heater
5	82.8	0.186	Heater
5	88	0.198	Heater
5	102	0.229	Heater
5	123	0.276	Heater
5	176	0.395	Heater
5	176	0.395	Heater
5	176	0.395	Heater
5	177	0.397	Heater
5	216.8	0.487	Heater
5	219	0.492	Heater
5	315	0.707	Heater
5	315	0.707	Heater
5	365.25	0.820	Heater
5	653	1.466	SMR Heater
5	342	0.768	Boiler
6	60	0.135	Heater
6	60	0.135	Heater
6	60	0.135	Heater

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
6	60	0.135	Heater
6	64	0.144	Heater
6	67	0.150	Heater
6	67	0.150	Heater
6	73	0.164	Heater
6	74	0.166	Heater
6	91	0.204	Heater
6	107.4	0.241	Heater
6	108	0.242	Heater
6	126	0.283	Heater
6	129	0.290	Heater
6	457	1.026	Heater
6	1247	2.800	SMR Heater/Gas Turbine
6	527	1.183	SMR Heater
6	291	0.653	Boiler
6	309	0.694	Boiler
6	340	0.763	Boiler
6	340	0.763	Boiler
7	41.3	0.093	Heater
7	60.2	0.135	Heater
7	116	0.260	Heater
7	76	0.171	Heater
7	110	0.247	Heater
7	135	0.303	Heater
7	460	1.033	SMR Heater
7	350	0.786	SMR Heater
7	142	0.319	Boiler
7	179	0.402	Boiler
7	250	0.561	Boiler
7	304	0.683	Boiler
8	70	0.157	Heater

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
8	153.6	0.345	Heater
8	153.6	0.345	Heater
8	175	0.393	Heater
8	175	0.393	Heater
8	350	0.786	Heater
8	340	0.763	SMR Heater
8	352	0.790	Boiler
8	352	0.790	Boiler
9	49	0.110	Heater
9	57	0.128	Heater
9	68	0.153	Heater
9	95	0.213	Heater
9	110	0.247	Heater
9	136	0.305	Heater
9	144	0.323	Heater
9	159.2	0.357	Heater
9	30	0.067	Heater
9	200	0.449	Heater
9	258	0.579	Heater
9	127.8	0.287	Boiler
9	245	0.550	Boiler
10	12.8	0.029	Heater
10	22.2	0.050	Heater
10	28	0.063	Heater
10	48	0.108	Heater
10	48	0.108	Heater
10	38.43	0.086	Heater
10	27.72	0.062	Heater
10	85	0.191	Heater
10	44.5	0.100	Boiler
13	785	1.763	SMR Heater
14	764	1.715	SMR Heater

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
15	780	1.751	SMR Heater
1	1326	9.033	Gas Turbine
1	1326	9.033	Gas Turbine
1	1326	9.033	Gas Turbine
1	1326	9.033	Gas Turbine
4	392	2.670	Gas Turbine
4	392	2.670	Gas Turbine
5	680	4.632	Gas Turbine
5	680	4.632	Gas Turbine
5	626	4.264	Gas Turbine
5	641	4.366	Gas Turbine
7	745	5.075	Gas Turbine
9	342	2.330	Gas Turbine
10	0	0.000	Gas Turbine
2	250	0.561	Coke Calciner
1	1337	2.571	FCCU
5	1816	3.493	FCCU
6	2137	4.109	FCCU
7	879	1.690	FCCU
9	531	1.193	FCCU

Total Ammonia Slip	**135.328**	**lb/hr**	**1.62**	**tons/day**

For Cells B13 through B14, Stack Pollutant Concentration x (20.9/(20.9-O2 Concentration))
http://www.aqmd.gov/docs/default-source/laboratory-procedures/methods-procedures/higho2protoco.pdf

Stack Pollutant Concentration = (5*17*8710)/(385*1000000)
http://www.aqmd.gov/docs/default-source/permitting/boiler_template.pdf

5ppm Ammonia Slip Limit
17 = NH3 Molecular Weight
8710 dscf per MMBTU for Natural Gas F-factor
385 ft3/lb-mol Molar Volume
1000000 BTU per MMBTU

Stack Correction	lb/MMBTU NH3	Facility Type
At 3% O2	0.002245275	Refinery
At 15% O2	0.006811937	Non-Refinery

Below lists the refinery equipment analyzed for ammonia slip in the December 2015 Final PEA for NOx RECLAIM

Refinery Facilities Evaluated in December 2015 Final PEA for NOx RECLAIM

Refinery Faciity Number	Heat Input Rate (MMBTU/hr)	NH3 Emission Rate (lb/hr)	Equipment Category
1	650	1.459	HEATER
1	550	1.235	HEATER
1	427	0.959	HEATER
1	310	0.696	HEATER
1	300	0.674	HEATER
1	255	0.573	HEATER
1	150	0.337	HEATER
1	130	0.292	HEATER
1	130	0.292	HEATER
1	130	0.292	HEATER
1	130	0.292	HEATER
1	120	0.269	HEATER
1	100	0.225	HEATER
1	89	0.200	HEATER

Refinery Faciity Number	Heat Input Rate (MMBTU/hr)	NH3 Emission Rate (lb/hr)	Equipment Category
3	112	0.251	BOILER
3	112	0.251	BOILER
4	199	0.447	HEATER
4	147	0.330	HEATER
4	140	0.314	BOILER
4	127	0.285	HEATER
4	95	0.213	HEATER
4	63	0.141	HEATER
4	60	0.135	HEATER
5	653	1.466	HEATER
5	365	0.820	HEATER
5	342	0.768	BOILER
5	315	0.707	HEATER
5	315	0.707	HEATER
5	220	0.494	HEATER
5	219	0.492	HEATER
5	217	0.487	HEATER
5	199	0.447	HEATER
5	177	0.397	HEATER
5	176	0.395	HEATER
5	176	0.395	HEATER
5	176	0.395	HEATER
5	125	0.281	HEATER
5	102	0.229	HEATER
5	88	0.198	HEATER
5	83	0.186	HEATER
5	63	0.141	HEATER
5	57	0.128	HEATER
5	57	0.128	HEATER
6	931	2.090	HEATER
6	457	1.026	HEATER
6	340	0.763	BOILER

Refinery Faciity Number	Heat Input Rate (MMBTU/hr)	NH3 Emission Rate (lb/hr)	Equipment Category
6	340	0.763	BOILER
6	309	0.694	BOILER
6	291	0.653	BOILER
6	161	0.361	HEATER
6	129	0.290	HEATER
6	126	0.283	HEATER
6	94	0.211	HEATER
6	91	0.204	HEATER
6	91	0.204	HEATER
6	74	0.166	HEATER
6	67	0.150	HEATER
6	67	0.150	HEATER
7	350	0.786	HEATER
7	304	0.683	BOILER 7
7	250	0.561	BOILER 6
7	179	0.402	BOILER 8
7	135	0.303	HEATER
7	110	0.247	HEATER
7	100	0.225	HEATER
7	76	0.171	HEATER
7	60	0.135	HEATER
8	352	0.790	BOILER
8	352	0.790	BOILER 11
8	350	0.786	HEATER
8	340	0.763	HEATER
8	175	0.393	HEATER
8	175	0.393	HEATER
8	154	0.346	HEATER
8	154	0.346	HEATER
8	70	0.157	HEATER
9	245	0.550	BOILER/new SCR

Refinery Faciity Number	Heat Input Rate (MMBTU/hr)	NH3 Emission Rate (lb/hr)	Equipment Category
9	200	0.449	HEATER
9	136	0.305	HEATER
9	128	0.287	BOILER
9	110	0.247	HEATER
9	95	0.213	HEATER
9	68	0.153	HEATER
1	1326	9.033	Gas Turbine
1	1326	9.033	Gas Turbine
1	1326	9.033	Gas Turbine
1	1326	9.033	Gas Turbine
4	392	2.670	Gas Turbine
4	392	2.670	Gas Turbine
5	680	4.632	Gas Turbine
5	680	4.632	Gas Turbine
5	792	5.395	Gas Turbine
6	926	6.308	Gas Turbine
7	745	5.075	Gas Turbine
1	45	0.101	SRU
5	55	0.123	SRU
5	55	0.123	SRU
5	99	0.222	SRU
6	100	0.225	SRU
8	28	0.063	SRU
2	250	0.561	Coke Calciner
4	535	1.201	FCCU

Refinery Faciity Number	Heat Input Rate (MMBTU/hr)	NH3 Emission Rate (lb/hr)	Equipment Category
5	758	1.702	FCCU
6	2391	5.369	FCCU
7	741	1.665	FCCU
9	520	1.168	FCCU

Subtotal Ammonia Slip from Refinery Facilities	**117.953**	**lb/hr**	**1.42**	**ton/day**

For Cells B13 through B15, Stack Pollutant Concentration x (20.9/(20.9-O2 Concentration))
http://www.aqmd.gov/docs/default-source/laboratory-procedures/methods-procedures/higho2protoco.pdf

Stack Pollutant Concentration = (5*17*8710)/(385*1000000)
http://www.aqmd.gov/docs/default-source/permitting/boiler_template.pdf
5ppm Ammonia Slip Limit
17 = NH3 Molecular Weight
8710 dscf per MMBTU for Natural Gas F-factor
385 ft3/lb-mol Molar Volume
1000000 BTU per MMBTU

Stack Correction	lb/MMBTU NH3	Equipment Type
At 0% O2	0.001922987	FCCU
At 3% O2	0.002245275	All Other Equipment
At 15% O2	0.006811937	Gas Turbines

Below lists all equipment in the 1109.1 universe which is assumed to either install SCR or have an existing SCR upgraded.

Facilities Subject to PR 1109.1

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
1	52	0.117	Heater
1	52	0.117	Heater
1	80	0.180	Heater
1	82	0.184	Heater
1	89	0.200	Heater
1	100	0.225	Heater
1	120	0.269	Heater
1	130	0.292	Heater
1	130	0.292	Heater
1	130	0.292	Heater
1	130	0.292	Heater

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
1	150	0.337	Heater
1	173	0.388	Heater
1	255	0.573	Heater
1	310	0.696	Heater
1	550	1.235	Heater
1	427	0.959	SMR Heater
1	650	1.459	SMR Heater
3	112.4	0.252	Boiler
3	112.4	0.252	Boiler
4	45	0.101	Heater
4	71.4	0.160	Heater
4	47.6	0.107	Heater
4	48.6	0.109	Heater
4	55.8	0.125	Heater
4	60	0.135	Heater
4	63	0.142	Heater
4	69	0.155	Heater
4	82.2	0.185	Heater
4	147	0.330	Heater
4	198.98	0.447	Heater
4	203.8	0.458	Heater
4	218.4	0.490	Heater
4	252	0.566	Heater
4	183.54	0.412	Boiler
4	183.54	0.412	Boiler
4	183.54	0.412	Boiler
4	183.54	0.412	Boiler
5	44	0.099	Heater
5	57	0.128	Heater
5	57	0.128	Heater
5	57	0.128	Heater

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
5	57	0.128	Heater
5	63	0.141	Heater
5	63	0.141	Heater
5	70	0.157	Heater
5	77	0.173	Heater
5	102	0.229	Heater
5	216.8	0.487	Heater
5	365.25	0.820	Heater
5	342	0.768	Boiler
6	67	0.150	Heater
6	67	0.150	Heater
6	73	0.164	Heater
6	74	0.166	Heater
6	91	0.204	Heater
6	107.4	0.241	Heater
6	108	0.242	Heater
6	126	0.283	Heater
6	129	0.290	Heater
6	457	1.026	Heater
6	527	1.183	SMR Heater
6	291	0.653	Boiler
6	309	0.694	Boiler
7	60.2	0.135	Heater
7	116	0.260	Heater
7	76	0.171	Heater
7	110	0.247	Heater
7	135	0.303	Heater
7	350	0.786	SMR Heater
7	142	0.319	Boiler
7	179	0.402	Boiler
7	250	0.561	Boiler

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
8	70	0.157	Heater
8	153.6	0.345	Heater
8	175	0.393	Heater
8	175	0.393	Heater
8	350	0.786	Heater
8	340	0.763	SMR Heater
8	352	0.790	Boiler
9	49	0.110	Heater
9	57	0.128	Heater
9	68	0.153	Heater
9	95	0.213	Heater
9	144	0.323	Heater
9	159.2	0.357	Heater
9	30	0.067	Heater
9	258	0.579	Heater
10	44.5	0.100	Boiler
4	392	2.670	Gas Turbine
4	392	2.670	Gas Turbine
5	680	4.632	Gas Turbine
5	680	4.632	Gas Turbine
5	626	4.264	Gas Turbine
2	250	0.561	Coke Calciner
7	879	1.690	FCCU
9	531	1.193	FCCU

Total Ammonia Slip	**53.900**	**lb/hr**	**0.65**	**tons/day**

For Cells B13 through B15, Stack Pollutant Concentration x (20.9/(20.9-O2 Concentration))
http://www.aqmd.gov/docs/default-source/laboratory-procedures/methods-procedures/higho2protoco.pdf

Stack Pollutant Concentration = (5*17*8710)/(385*1000000)
http://www.aqmd.gov/docs/default-source/permitting/boiler_template.pdf
5ppm Ammonia Slip Limit
17 = NH3 Molecular Weight
8710 dscf per MMBTU for Natural Gas F-factor
385 ft3/lb-mol Molar Volume
1000000 BTU per MMBTU

Stack Correction	lb/MMBTU NH3	Equipment Type
At 0% O2	0.001922987	FCCU
At 3% O2	0.002245275	All Other Equipment
At 15% O2	0.006811937	Gas Turbines

per Sarady's Email on 2/17/21

Below lists all equipment in the 1109.1 universe which is assumed to either install SCR or have an existing SCR upgraded but ammonia slip for equipment previously analyzed in the Dec 2015 Final PEA is removed.

Facilities Subject to PR 1109.1

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
1	52	0.117	Heater
1	52	0.117	Heater
1	80	0.180	Heater
1	82	0.184	Heater
1	89		Heater
1	100		Heater
1	120		Heater
1	130		Heater
1	130		Heater
1	130		Heater
1	130		Heater

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category	
1	150		Heater	
1	173		Heater	reasc 300
1	255		Heater	
1	310		Heater	
1	550		Heater	
1	427		SMR Heater	
1	650		SMR Heater	
3	112.4		Boiler	
3	112.4		Boiler	
4	45	0.101	Heater	
4	47.6	0.107	Heater	
4	71.4		Heater	reasc 95
4	48.6		Heater	reasc 128
4	55.8	0.125	Heater	
4	60		Heater	
4	63		Heater	
4	69		Heater	reasc 140
4	82.2	0.185	Heater	
4	147		Heater	
4	198.98		Heater	
4	203.8	0.458	Heater	
4	218.4	0.490	Heater	
4	252	0.566	Heater	
4	183.54	0.412	Boiler	
4	183.54	0.412	Boiler	
4	183.54	0.412	Boiler	
4	183.54	0.412	Boiler	
5	44		Heater	
5	57		Heater	
5	57		Heater	
5	57		Heater	

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category	
5	57		Heater	
5	63		Heater	
5	63		Heater	
5	70		Heater	
5	77		Heater	
5	102		Heater	
5	216.8		Heater	
5	365.25		Heater	
5	342	0.768	Boiler	
6	67		Heater	
6	67		Heater	
6	73		Heater	reasc 94
6	74		Heater	
6	91		Heater	
6	107.4		Heater	reasc 340
6	108		Heater	reasc 161
6	126		Heater	
6	129		Heater	
6	457		Heater	
6	527		SMR Heater	reasc 931
6	291		Boiler	
6	309		Boiler	
7	60.2		Heater	
7	116	0.260	Heater	
7	76		Heater	
7	110		Heater	
7	135		Heater	
7	350		SMR Heater	
7	142		Boiler	reasc 304
7	179		Boiler	
7	250		Boiler	

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category	
8	70		Heater	
8	153.6		Heater	
8	175		Heater	
8	175		Heater	
8	350		Heater	
8	340		SMR Heater	
8	352		Boiler	
9	49		Heater	reasc 128
9	57		Heater	reasc 136
9	68		Heater	
9	95		Heater	
9	144		Heater	reasc 200
9	159.2		Heater	reasc 245
9	30		Heater	reasc 110
9	258	0.579	Heater	
10	44.5	0.100	Boiler	
4	392		Gas Turbine	
4	392		Gas Turbine	
5	680		Gas Turbine	
5	680		Gas Turbine	
5	626		Gas Turbine	
2	250		Coke Calciner	
7	879		FCCU	
9	531		FCCU	

Total Ammonia Slip	**5.985**	**lb/hr**	**0.07**	**tons/day**

Offsite Consequence Analysis

Ammonia Slip Conc at the Exit of the Stack, ppm	Dispersion Factor	Molecular Weight, g/mol	Peak Conc at a Receptor 25 m from the Stack, ug/m3	Acute REL, ug/m3	Chronic REL, ug/m3	Acute Hazard Index	Chronic Hazard Index
5	0.01	17.03	35	3,200	200	0.01	0.17

Ammonia slip is limited to five ppm by permitting.

Conc., ug/m3 = (conc., ppm x 1,000 x molecular weight, g/mol)/24.5 m3/kmol

Based on the Staff Report for Toxic Air Contaminants 1401.1 – Requirements for New and Relocated Facilities Near Schools, and 1402 – Control of Toxic Air Contaminants from Existing Source, June 2015 the concentration at a receptor 25 m from a stack would be much less than one percent of the concentration at the release from the exist of the stack.

Hazard index = conc. at receptor 25 m from stack, ug/m3/REL, ug/m3

PM2.5 Calculation Based on Estimated NOx Reductions and Ammonia Slip

	Estimated NOx Reductions (tpd)	Reduction in PM2.5 Concentration (µg/m3)	Estimated Ammonia Slip (tpd)	Increase in PM Concentration (µg/m3)	Net Change in PM2.5 concentration (µg/m3)
December 2015 Final PEA for NOx RECLAIM	14	0.7	1.63	0.6	-0.1
SEA for PR 1109.1	7	0.35	0.646800118	0.24	-0.11

This calculation assumes the same modeling parameters used in the PM2.5 concentration for the Decemeber 2015 Final PEA for NOx RECLAIM.

Comparison of Ammonia Slip Analyses in December 2015 Final PEA for NOx RECLAIM with PR 1109.1

December 2015 Final PEA for NOx RECLAIM	**Ammonia Slip Estimate from December 2015 (tons/day)**	**Updated Ammonia Slip Estimate to remove shutdown equipment (tons/day)***	**NOx RTCs Reductions (Weighted) Claimed in December 2015 Final PEA for NOx RECLAIM (tons/day)[see Table U.2 Final Staff Report for NOx RECLAIM p. 208)**	**Actual NOx Emission Reductions from Off-Ramping NOx RECLAIM to Command-and-Control (tons/day)**	**Annual PM2.5 Emission Reductions from RTC Reductions per December 2015 NOx RECLAIM (micrograms/cubic meter)**	**Concurrent Increase in Annual PM2.5 Emissions from Ammonia Slip Usage per December 2015 NOx RECLAIM (micrograms/cubic meter)**	**Net Benefit of Annual PM2.5 Reductions from December 2015 NOx RECLAIM**
Non-Refinery Facilities	0.213	0.213	4.42	5.05^			
Refinery Facilities (1 through 9)	1.415	1.400	9.58	8.95#	**0.7**	**0.6**	**0.1**
Total	**1.63**	**1.62**	**14**	**14**			

* removes facility 4 fccu nh3 slip due to shutdown of fccu which represents 0.17 ton/day NOx reductions

^See below other off-ramp Rules analysis; # amount remaining needed by PR 1109.1

PR 1109.1: Same Refinery Facilities Evaluated in December 2015 Final PEA for NOx RECLAIM (1 through 9) plus additional facilities 11-14~	**Ammonia Slip (tons/day)**	**NOx Emission Reductions for PR 1109.1 (tons/day)**
Only equipment utlizing ammonia subject to PR 1109.1 but that were not previously analyzed in December 2015 Final PEA for NOx RECLAIM, but the NH3 slip for NOx RECLAIM was overestimated	0.057	
All PR 1109.1 Equipment Utilizing Ammonia (corresponds to Refinery Facilities category December 2015 Final PEA for NOx RECLAIM)	**0.625**	**7**

This is less than refinery portion of NOx RECLAIM and less than entire ammonia slip portion for both refinery and non-refinery facilities combined

NOx RECLAIM Off-Ramp Rule Amendments for Non-Refinery Facilities	**Date of Amendment**	**NOx Emission Reductions from Off-Ramp Rules for Non-Refinery Facilities (tons/day)**
1135	11/2/2018	1.7
1146, 1146.1, & 1146.2	12/7/2018	0.27
1134	4/5/2019	2.8
1110.2	11/1/2019	0.28
	total	**5.05**

For Cells B13 through B15, Stack Pollutant Concentration x (20.9/(20.9-O2 Concentration))
http://www.aqmd.gov/docs/default-source/laboratory-procedures/methods-procedures/higho2protoco.pdf

Stack Pollutant Concentration = (5*17*8710)/(385*1000000)
http://www.aqmd.gov/docs/default-source/permitting/boiler_template.pdf
5ppm Ammonia Slip Limit
17 = NH3 Molecular Weight
8710 dscf per MMBTU for Natural Gas F-factor
385 ft3/lb-mol Molar Volume
1000000 BTU per MMBTU

Stack Correction	lb/MMBTU NH3	Equipment Type
At 0% O2	0.001922987	FCCU
At 3% O2	0.002245275	All Other Equipment
At 15% O2	0.006811937	Gas Turbines

per Sarady's Email on 2/17/21

Below lists all equipment in the 1109.1 universe which has existing SCR, is assumed to install SCR, or has an existing SCR that will be upgraded. Equipment has not been double-counted.

Facilities Subject to PR 1109.1

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
1	52	0.117	Heater
1	52	0.117	Heater
1	80	0.180	Heater
1	82	0.184	Heater
1	89	0.200	Heater
1	100	0.225	Heater
1	120	0.269	Heater
1	130	0.292	Heater
1	130	0.292	Heater
1	130	0.292	Heater
1	130	0.292	Heater
1	150	0.337	Heater
1	173	0.388	Heater

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
1	255	0.573	Heater
1	300	0.674	Heater
1	310	0.696	Heater
1	550	1.235	Heater
1	427	0.959	SMR Heater
1	650	1.459	SMR Heater
3	112	0.252	Boiler
4	24	0.053	Heater
4	29	0.064	Heater
4	31	0.071	Heater
4	31	0.071	Heater
4	36	0.081	Heater
4	45	0.101	Heater
4	48	0.107	Heater
4	48	0.107	Heater
4	49	0.109	Heater
4	50	0.112	Heater
4	56	0.125	Heater
4	60	0.135	Heater
4	63	0.142	Heater
4	69	0.155	Heater
4	71	0.160	Heater
4	82	0.185	Heater
4	95	0.213	Heater
4	127	0.286	Heater
4	147	0.330	Heater
4	199	0.447	Heater
4	204	0.458	Heater
4	218	0.490	Heater
4	252	0.566	Heater
4	145.97	0.328	SMR Heater
4	139.5	0.313	Boiler

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
4	183.54	0.412	Boiler
4	183.54	0.412	Boiler
5	33.4	0.075	Heater
5	33.4	0.075	Heater
5	44	0.099	Heater
5	57	0.128	Heater
5	57	0.128	Heater
5	57	0.128	Heater
5	57	0.128	Heater
5	63	0.141	Heater
5	63	0.141	Heater
5	70	0.157	Heater
5	77	0.173	Heater
5	82.8	0.186	Heater
5	88	0.198	Heater
5	102	0.229	Heater
5	123	0.276	Heater
5	176	0.395	Heater
5	176	0.395	Heater
5	176	0.395	Heater
5	177	0.397	Heater
5	216.8	0.487	Heater
5	219	0.492	Heater
5	315	0.707	Heater
5	315	0.707	Heater
5	365.25	0.820	Heater
5	653	1.466	SMR Heater
5	342	0.768	Boiler
6	60	0.135	Heater
6	60	0.135	Heater
6	60	0.135	Heater
6	60	0.135	Heater

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
6	64	0.144	Heater
6	67	0.150	Heater
6	67	0.150	Heater
6	73	0.164	Heater
6	74	0.166	Heater
6	91	0.204	Heater
6	107.4	0.241	Heater
6	108	0.242	Heater
6	126	0.283	Heater
6	129	0.290	Heater
6	457	1.026	Heater
6	1247	2.800	SMR Heater/Gas Turbine
6	527	1.183	SMR Heater
6	291	0.653	Boiler
6	309	0.694	Boiler
6	340	0.763	Boiler
6	340	0.763	Boiler
7	41.3	0.093	Heater
7	60.2	0.135	Heater
7	116	0.260	Heater
7	76	0.171	Heater
7	110	0.247	Heater
7	135	0.303	Heater
7	460	1.033	SMR Heater
7	350	0.786	SMR Heater
7	142	0.319	Boiler
7	179	0.402	Boiler
7	250	0.561	Boiler
7	304	0.683	Boiler
8	70	0.157	Heater
8	153.6	0.345	Heater

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
8	153.6	0.345	Heater
8	175	0.393	Heater
8	175	0.393	Heater
8	350	0.786	Heater
8	340	0.763	SMR Heater
8	352	0.790	Boiler
8	352	0.790	Boiler
9	49	0.110	Heater
9	57	0.128	Heater
9	68	0.153	Heater
9	95	0.213	Heater
9	110	0.247	Heater
9	136	0.305	Heater
9	144	0.323	Heater
9	159.2	0.357	Heater
9	30	0.067	Heater
9	200	0.449	Heater
9	258	0.579	Heater
9	127.8	0.287	Boiler
9	245	0.550	Boiler
10	12.8	0.029	Heater
10	22.2	0.050	Heater
10	28	0.063	Heater
10	48	0.108	Heater
10	48	0.108	Heater
10	38.43	0.086	Heater
10	27.72	0.062	Heater
10	85	0.191	Heater
10	44.5	0.100	Boiler
13	785	1.763	SMR Heater
14	764	1.715	SMR Heater
15	780	1.751	SMR Heater

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
1	1326	9.033	Gas Turbine
1	1326	9.033	Gas Turbine
1	1326	9.033	Gas Turbine
1	1326	9.033	Gas Turbine
4	392	2.670	Gas Turbine
4	392	2.670	Gas Turbine
5	680	4.632	Gas Turbine
5	680	4.632	Gas Turbine
5	626	4.264	Gas Turbine
5	641	4.366	Gas Turbine
7	745	5.075	Gas Turbine
9	342	2.330	Gas Turbine
10	0	0.000	Gas Turbine
2	250	0.561	Coke Calciner
1	1337	2.571	FCCU
5	1816	3.493	FCCU
6	2137	4.109	FCCU
7	879	1.690	FCCU
9	531	1.193	FCCU

Total Ammonia Slip	**123.113**	**lb/hr**	**1.48**	**tons/day**

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For Cells B13 through B14, Stack Pollutant Concentration x (20.9/(20.9-O2 Concentration))
http://www.aqmd.gov/docs/default-source/laboratory-procedures/methods-procedures/higho2protoco.pdf

Stack Pollutant Concentration = (5*17*8710)/(385*1000000)
http://www.aqmd.gov/docs/default-source/permitting/boiler_template.pdf

5ppm Ammonia Slip Limit
17 = NH3 Molecular Weight
8710 dscf per MMBTU for Natural Gas F-factor
385 ft3/lb-mol Molar Volume
1000000 BTU per MMBTU

Stack Correction	lb/MMBTU NH3	Facility Type
At 3% O2	0.002245275	Refinery
At 15% O2	0.006811937	Non-Refinery

Below lists the refinery equipment analyzed for ammonia slip in the December 2015 Final PEA for NOx RECLAIM

Refinery Facilities Evaluated in December 2015 Final PEA for NOx RECLAIM

Refinery Faciity Number	Heat Input Rate (MMBTU/hr)	NH3 Emission Rate (lb/hr)	Equipment Category
1	650	1.459	HEATER
1	550	1.235	HEATER
1	427	0.959	HEATER
1	310	0.696	HEATER
1	300	0.674	HEATER
1	255	0.573	HEATER
1	150	0.337	HEATER
1	130	0.292	HEATER
1	130	0.292	HEATER
1	130	0.292	HEATER
1	130	0.292	HEATER
1	120	0.269	HEATER
1	100	0.225	HEATER
1	89	0.200	HEATER

Refinery Faciity Number	Heat Input Rate (MMBTU/hr)	NH3 Emission Rate (lb/hr)	Equipment Category
3	112	0.251	BOILER
3	112	0.251	BOILER
4	199	0.447	HEATER
4	147	0.330	HEATER
4	140	0.314	BOILER
4	127	0.285	HEATER
4	95	0.213	HEATER
4	63	0.141	HEATER
4	60	0.135	HEATER
5	653	1.466	HEATER
5	365	0.820	HEATER
5	342	0.768	BOILER
5	315	0.707	HEATER
5	315	0.707	HEATER
5	220	0.494	HEATER
5	219	0.492	HEATER
5	217	0.487	HEATER
5	199	0.447	HEATER
5	177	0.397	HEATER
5	176	0.395	HEATER
5	176	0.395	HEATER
5	176	0.395	HEATER
5	125	0.281	HEATER
5	102	0.229	HEATER
5	88	0.198	HEATER
5	83	0.186	HEATER
5	63	0.141	HEATER
5	57	0.128	HEATER
5	57	0.128	HEATER
6	931	2.090	HEATER
6	457	1.026	HEATER
6	340	0.763	BOILER

Refinery Faciity Number	Heat Input Rate (MMBTU/hr)	NH3 Emission Rate (lb/hr)	Equipment Category
6	340	0.763	BOILER
6	309	0.694	BOILER
6	291	0.653	BOILER
6	161	0.361	HEATER
6	129	0.290	HEATER
6	126	0.283	HEATER
6	94	0.211	HEATER
6	91	0.204	HEATER
6	91	0.204	HEATER
6	74	0.166	HEATER
6	67	0.150	HEATER
6	67	0.150	HEATER
7	350	0.786	HEATER
7	304	0.683	BOILER 7
7	250	0.561	BOILER 6
7	179	0.402	BOILER 8
7	135	0.303	HEATER
7	110	0.247	HEATER
7	100	0.225	HEATER
7	76	0.171	HEATER
7	60	0.135	HEATER
8	352	0.790	BOILER
8	352	0.790	BOILER 11
8	350	0.786	HEATER
8	340	0.763	HEATER
8	175	0.393	HEATER
8	175	0.393	HEATER
8	154	0.346	HEATER
8	154	0.346	HEATER
8	70	0.157	HEATER
9	245	0.550	BOILER/new SCR

Refinery Faciity Number	Heat Input Rate (MMBTU/hr)	NH3 Emission Rate (lb/hr)	Equipment Category
9	200	0.449	HEATER
9	136	0.305	HEATER
9	128	0.287	BOILER
9	110	0.247	HEATER
9	95	0.213	HEATER
9	68	0.153	HEATER
1	1326	9.033	Gas Turbine
1	1326	9.033	Gas Turbine
1	1326	9.033	Gas Turbine
1	1326	9.033	Gas Turbine
4	392	2.670	Gas Turbine
4	392	2.670	Gas Turbine
5	680	4.632	Gas Turbine
5	680	4.632	Gas Turbine
5	792	5.395	Gas Turbine
6	926	6.308	Gas Turbine
7	745	5.075	Gas Turbine
1	45	0.101	SRU
5	55	0.123	SRU
5	55	0.123	SRU
5	99	0.222	SRU
6	100	0.225	SRU
8	28	0.063	SRU
2	250	0.561	Coke Calciner
4	535	1.201	FCCU

Refinery Faciity Number	Heat Input Rate (MMBTU/hr)	NH3 Emission Rate (lb/hr)	Equipment Category
5	758	1.702	FCCU
6	2391	5.369	FCCU
7	741	1.665	FCCU
9	520	1.168	FCCU

Subtotal Ammonia Slip from Refinery Facilities	**117.953**	**lb/hr**	**1.42**	**ton/day**

For Cells B13 through B15, Stack Pollutant Concentration x (20.9/(20.9-O2 Concentration))
http://www.aqmd.gov/docs/default-source/laboratory-procedures/methods-procedures/higho2protoco.pdf

Stack Pollutant Concentration = (5*17*8710)/(385*1000000)
http://www.aqmd.gov/docs/default-source/permitting/boiler_template.pdf
5ppm Ammonia Slip Limit
17 = NH3 Molecular Weight
8710 dscf per MMBTU for Natural Gas F-factor
385 ft3/lb-mol Molar Volume
1000000 BTU per MMBTU

Stack Correction	lb/MMBTU NH3	Equipment Type
At 0% O2	0.001922987	FCCU
At 3% O2	0.002245275	All Other Equipment
At 15% O2	0.006811937	Gas Turbines

Below lists all equipment in the 1109.1 universe which is assumed to either install SCR or have an existing SCR upgraded.

Facilities Subject to PR 1109.1

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
1	52	0.117	Heater
1	80	0.180	Heater
1	82	0.184	Heater
1	89	0.200	Heater
1	100	0.225	Heater
1	120	0.269	Heater
1	130	0.292	Heater
1	130	0.292	Heater
1	130	0.292	Heater
1	130	0.292	Heater
1	150	0.337	Heater

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Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
1	173	0.388	Heater
1	310	0.696	Heater
1	550	1.235	Heater
1	427	0.959	SMR Heater
1	650	1.459	SMR Heater
3	112.4	0.252	Boiler
4	45	0.101	Heater
4	71.4	0.160	Heater
4	48.6	0.109	Heater
4	55.8	0.125	Heater
4	60	0.135	Heater
4	69	0.155	Heater
4	82.2	0.185	Heater
4	94.7	0.213	Heater
4	127.2	0.286	Heater
4	198.98	0.447	Heater
4	203.8	0.458	Heater
4	218.4	0.490	Heater
4	252	0.566	Heater
4	183.54	0.412	Boiler
4	183.54	0.412	Boiler
5	44	0.099	Heater
5	57	0.128	Heater
5	57	0.128	Heater
5	57	0.128	Heater
5	57	0.128	Heater
5	63	0.141	Heater
5	63	0.141	Heater
5	70	0.157	Heater
5	77	0.173	Heater
5	102	0.229	Heater

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
5	216.8	0.487	Heater
5	365.25	0.820	Heater
5	342	0.768	Boiler
6	67	0.150	Heater
6	67	0.150	Heater
6	73	0.164	Heater
6	74	0.166	Heater
6	91	0.204	Heater
6	107.4	0.241	Heater
6	108	0.242	Heater
6	126	0.283	Heater
6	129	0.290	Heater
6	457	1.026	Heater
6	527	1.183	SMR Heater
6	291	0.653	Boiler
6	309	0.694	Boiler
7	60.2	0.135	Heater
7	116	0.260	Heater
7	76	0.171	Heater
7	110	0.247	Heater
7	135	0.303	Heater
7	350	0.786	SMR Heater
7	142	0.319	Boiler
7	179	0.402	Boiler
7	250	0.561	Boiler
8	70	0.157	Heater
8	153.6	0.345	Heater
8	175	0.393	Heater
8	175	0.393	Heater
8	350	0.786	Heater
8	340	0.763	SMR Heater

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
8	352	0.790	Boiler
9	49	0.110	Heater
9	57	0.128	Heater
9	68	0.153	Heater
9	95	0.213	Heater
9	144	0.323	Heater
9	159.2	0.357	Heater
9	30	0.067	Heater
9	258	0.579	Heater
10	44.5	0.100	Boiler
4	392	2.670	Gas Turbine
4	392	2.670	Gas Turbine
5	680	4.632	Gas Turbine
5	680	4.632	Gas Turbine
5	626	4.264	Gas Turbine
2	250	0.561	Coke Calciner
7	879	1.690	FCCU
9	531	1.193	FCCU

Total Ammonia Slip	**52.054**	**lb/hr**	**0.62**	**tons/day**

For Cells B13 through B15, Stack Pollutant Concentration x (20.9/(20.9-O2 Concentration))
http://www.aqmd.gov/docs/default-source/laboratory-procedures/methods-procedures/higho2protoco.pdf

Stack Pollutant Concentration = (5*17*8710)/(385*1000000)
http://www.aqmd.gov/docs/default-source/permitting/boiler_template.pdf
5ppm Ammonia Slip Limit
17 = NH3 Molecular Weight
8710 dscf per MMBTU for Natural Gas F-factor
385 ft3/lb-mol Molar Volume
1000000 BTU per MMBTU

Stack Correction	lb/MMBTU NH3	Equipment Type
At 0% O2	0.001922987	FCCU
At 3% O2	0.002245275	All Other Equipment
At 15% O2	0.006811937	Gas Turbines

per Sarady's Email on 2/17/21

Below lists all equipment in the 1109.1 universe which is assumed to either install SCR or have an existing SCR upgraded but ammonia slip for equipment previously analyzed in the Dec 2015 Final PEA is removed.

Facilities Subject to PR 1109.1

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category
1	52	0.117	Heater
1	80	0.180	Heater
1	82		Heater
1	89		Heater
1	100		Heater
1	120		Heater
1	130		Heater
1	130		Heater
1	130		Heater
1	130		Heater
1	150		Heater

reasc 255

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category	
1	173		Heater	reasc 300
1	310		Heater	
1	550		Heater	
1	427		SMR Heater	
1	650		SMR Heater	
3	112.4		Boiler	
4	45	0.101	Heater	
4	71.4	0.160	Heater	
4	48.6	0.109	Heater	
4	55.8		Heater	reasc 63
4	60		Heater	
4	69		Heater	reasc 140
4	82.2		Heater	reasc 147
4	94.7		Heater	
4	127.2		Heater	
4	198.98		Heater	
4	203.8	0.458	Heater	
4	218.4	0.490	Heater	
4	252	0.566	Heater	
4	183.54	0.412	Boiler	
4	183.54	0.412	Boiler	
5	44		Heater	
5	57		Heater	
5	57		Heater	
5	57		Heater	
5	57		Heater	
5	63		Heater	
5	63		Heater	
5	70		Heater	
5	77		Heater	
5	102		Heater	

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category	
5	216.8		Heater	
5	365.25		Heater	
5	342	0.768	Boiler	
6	67		Heater	
6	67		Heater	
6	73		Heater	reasc 94
6	74		Heater	
6	91		Heater	
6	107.4		Heater	reasc 340
6	108		Heater	reasc 161
6	126		Heater	
6	129		Heater	
6	457		Heater	
6	527		SMR Heater	reasc 931
6	291		Boiler	
6	309		Boiler	
7	60.2		Heater	
7	116	0.260	Heater	
7	76		Heater	
7	110		Heater	
7	135		Heater	
7	350		SMR Heater	
7	142		Boiler	reasc 304
7	179		Boiler	
7	250		Boiler	
8	70		Heater	
8	153.6		Heater	
8	175		Heater	
8	175		Heater	
8	350		Heater	
8	340		SMR Heater	

Facility Code	Heat Input Rate (MMBTU/hr)	NH3 slip Emission Rate (lb/hr)	Equipment Category	
8	352		Boiler	
9	49		Heater	reasc 128
9	57		Heater	reasc 136
9	68		Heater	
9	95		Heater	
9	144		Heater	reasc 200
9	159.2		Heater	reasc 245
9	30		Heater	reasc 110
9	258	0.579	Heater	
10	44.5	0.100	Boiler	
4	392		Gas Turbine	
4	392		Gas Turbine	
5	680		Gas Turbine	
5	680		Gas Turbine	
5	626		Gas Turbine	
2	250		Coke Calciner	
7	879		FCCU	
9	531		FCCU	

Total Ammonia Slip	**4.712**	**lb/hr**	**0.06**	**tons/day**

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Offsite Consequence Analysis

Ammonia Slip Conc at the Exit of the Stack, ppm	Dispersion Factor	Molecular Weight, g/mol	Peak Conc at a Receptor 25 m from the Stack, ug/m3	Acute REL, ug/m3	Chronic REL, ug/m3	Acute Hazard Index	Chronic Hazard Index
5	0.01	17.03	35	3,200	200	0.01	0.17

Ammonia slip is limited to five ppm by permitting.

Conc., ug/m3 = (conc., ppm x 1,000 x molecular weight, g/mol)/24.5 m3/kmol

Based on the Staff Report for Toxic Air Contaminants 1401.1 – Requirements for New and Relocated Facilities Near Schools, and 1402 – Control of Toxic Air Contaminants from Existing Source, June 2015 the concentration at a receptor 25 m from a stack would be much less than one percent of the concentration at the release from the exist of the stack.

Hazard index = conc. at receptor 25 m from stack, ug/m3/REL, ug/m3

PM2.5 Calculation Based on Estimated NOx Reductions and Ammonia Slip

	Estimated NOx Reductions (tpd)	Reduction in PM2.5 Concentration (µg/m3)	Estimated Ammonia Slip (tpd)	Increase in PM Concentration (µg/m3)	Net Change in PM2.5 concentration (µg/m3)
December 2015 Final PEA for NOx RECLAIM	14	0.7	1.63	0.6	-0.1
SEA for PR 1109.1	7	0.35	0.625	0.23	-0.12

This calculation assumes the same modeling parameters used in the PM2.5 concentration for the Decemeber 2015 Final PEA for NOx RECLAIM.

APPENDIX F

Comment Letters Received on the Draft SEA and Responses to Comments

APPENDIX F: TABLE OF CONTENTS

CHAPTER 1 INTRODUCTION

1.1 OVERVIEW

This appendix to the Final SEA has been prepared in accordance with the California Environmental Quality Act (CEQA) and the South Coast Air Quality Management District's (South Coast AQMD) Certified Regulatory Program Guidelines. Public Resources Code Section 21080.5, CEQA Guidelines Section 15251(l), and South Coast AQMD's Certified Regulatory Program (codified under Rule 110) require that the final action on PRs 1109.1 429., PARs 1304 and 2005 and proposed rescinded Rule 1109 include written responses to issues raised during the public process. South Coast AQMD Rule 110 (the rule which codifies and implements the South Coast AQMD's certified regulatory program) does not impose any greater requirements for summarizing and responding to comments than is required for an environmental impact report under CEQA.

1.2 CEQA PROCESS OF THE DRAFT SEA

The Draft SEA was released for a 46-day public review and comment period from September 3, 2021 to October 19, 2021. A Notice of Completion (NOC) was filed with the Governor's Office of Planning and Research (OPR) (State Clearinghouse (SCH) # 2014121018) and posted on the State Clearinghouse's CEQAnet Web Portal at: https://ceqanet.opr.ca.gov/2014121018/3. The electronic filing and posting of the NOC and the Draft SEA were implemented in accordance with Governor Newsom's Executive Orders N-54-20 (April 22, 2020) and N-80-20 (September 23, 2020) in response to the threat of COVID-19. Pursuant to Executive Order N-80-20, signed on September 23, 2020, certain requirements for filing, noticing, and posting of CEQA documents with county clerk offices have been conditionally suspended. The NOC was distributed using electronic mail to various government agencies and other interested agencies, organizations, and individuals (collectively referred to as the public). The NOC was also provided to all California Native American Tribes (Tribes) that requested to be on the Native American Heritage Commission's (NAHC) notification list per Public Resources Code Section 21080.3.1(b)(1). The NAHC notification list provides a 30-day period during which a Tribe may respond to the formal notice, in writing, requesting consultation on the Draft SEA. Additionally, the NOC was published in the Los Angeles Times on September 3, 2021. The Draft SEA was posted on South Coast AQMD's website at: http://www.aqmd.gov/home/research/documents-reports/lead-agency-scaqmd-projects. An email notification of the availability of the NOC and the Draft SEA was also sent to interested parties on September 3, 2021.

1.3 LIST OF COMMENTERS

Five comment letters were received by South Coast AQMD during the Draft SEA public review and comment period and one additional comment letter was received after the public review and comment period closed. This appendix contains responses to comments received relative to the analysis in the Draft SEA. Responses to comments received relative to draft rule language contained in PRs 1109.1 and 429.1, PARs 1304 and 2005 and proposed rescinded Rule 1109 can be found in Appendix F of the Final Staff Report.

For the purposes of identifying and responding to comments on the Draft EA, comment letters are assigned a reference number (top left-hand corner of the first page of each letter) and each comment within each letter is bracketed and assigned a comment number. The following is a list of comment letters received relative to the Draft SEA along with the date each letter was submitted.

Reference Number	Comment Letters	Date Submitted	Page No.
Received During the Public Review Period			
1	Santa Ynez Band of Chumash Indians	September 13, 2021	F-5
2	San Manuel Band of Mission Indians	September 20, 2021	F-7
3	Santa Ynez Band of Chumash Indians	October 11, 2021	F-11
4	Tesoro Refining & Marketing Company LLC	October 19, 2021	F-13
5	Torrance Refining Company	October 19, 2021	F-26
Received After the Close of the Public Review and Comment Period			
6	Western States Petroleum Association (WSPA)	October 20, 2021	F-33

For any response in this appendix that require an update elsewhere in this SEA, the response will indicate that a change has been made and where the change is located in the Final SEA. Additions to text are reflected in underlined text and deletions are reflected in ~~strikethrough~~ text.

Pursuant to CEQA Guidelines Section 15088(a) and South Coast AQMD Rule 110(d), South Coast AQMD is required to evaluate and provide written responses to only the comments received during the public comment period of the SEA which raise significant environmental issues. South Coast AQMD staff has reviewed the comments submitted, updated the SEA to reflect the responses to the comments, and determined that none of the comments raise significant environmental issues and none of the revisions to the SEA contain the type of significant new information that requires recirculation of the Draft SEA for further public comment under CEQA Guidelines Sections 15073.5 and 15088.5. Further, none of the comments indicate that the proposed project will result in a significant new environmental impact not previously disclosed in the Draft SEA. Additionally, none of comments indicate that there would be a substantial increase in the severity of a previously identified environmental impact that will not be mitigated, or that there would be any of the other circumstances requiring recirculation as described in CEQA Guidelines Sections 15073.5 and 15088.5.

1.4 CEQA REQUIREMENTS REGARDING COMMENTS AND RESPONSES

CEQA Guidelines Section 15204(b) outlines parameters for submitting comments and reminds persons and public agencies that the focus of review and comment of the Draft SEA should be "on the proposed finding that the project will not have a significant effect on the environment." If persons and public agencies believe that the proposed project may have a significant effect, the commenter should: 1) identify the specific effect; 2) explain why they believe the effect would occur; and 3) explain why they believe the effect would be significant. Comments are most helpful when they are as specific as possible. At the same time, reviewers of the SEA should be aware that CEQA does not require a lead agency to conduct every test or perform all research, study, and experimentation recommended or demanded by commenters.

CEQA Guidelines Section 15204(c) further advises, "Reviewers should explain the basis for their comments, and should submit data or references offering facts, reasonable assumptions based on facts, or expert opinion supported by facts in support of the comments. Pursuant to CEQA

Guidelines Section 15064, an effect shall not be considered significant in the absence of substantial evidence." CEQA Guidelines Section 15204(e) also states, "This section shall not be used to restrict the ability of reviewers to comment on the general adequacy of a document or of the lead agency to reject comments not focused as recommended by this section."

Written responses have been prepared pursuant to CEQA Guidelines Section 15088 and South Coast AQMD Rule 110 and the level of detail contained in each response corresponds to the level of detail provided in the comment (i.e. responses to general comments may be general).

CHAPTER 2 COMMENT LETTERS AND RESPONSES

2.1 COMMENT LETTERS RECEIVED DURING THE PUBLIC REVIEW PERIOD

This section includes responses to the five comment letters received by South Coast AQMD during the 46-day public review and comment period from September 3, 2021 to October 19, 2021 (5:00 p.m.).

COMMENT LETTER #1 – Santa Ynez Band of Chumash Indians, September 13, 2021 (p. 1 of 1)

SANTA YNEZ CHUMASH
TRIBAL ELDER'S COUNCIL
TO PROTECT AND PRESERVE TRIBAL ANCESTRY, TRADITIONS AND CULTURE

Santa Ynez Band of Chumash Indians
Tribal Elders' Council
P.O. Box 517 ◆ Santa Ynez ◆ CA ◆ 93460
Phone: (805)688-7997 ◆ Fax: (805)688-9578 ◆ Email: elders@santaynezchuhmash.org

September 13, 2021

South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765-4178

Att.: Kevin Ni

Re: Draft Subsequent Environmental Assessment (SEA)

Dear Mr. Ni:

Thank you for contacting the Tribal Elders' Council for the Santa Ynez Band of Chumash Indians.

At this time, the Elders' Council requests no further consultation on this project; however, if supplementary literature reveals additional information, or if the scope of the work changes, we kindly ask to be notified. 1-1

If you decide to have the presence of a Native American monitor in place during ground disturbance to assure that any cultural items unearthed be identified as quickly as possible, please contact our office or Chumash of the project area.

Thank you for remembering that at one time our ancestors walked this sacred land.

Sincerely Yours,
Kelsie Merrick

Kelsie Merrick
Administrative Assistant | Elders' Council and Culture Department
Santa Ynez Band of Chumash Indians | Tribal Hall
(805) 688-7997 ext. 7516
kmerrick@santaynezchumash.org

RESPONSE TO COMMENT LETTER #1 – Santa Ynez Band of Chumash Indians, September 13, 2021

Response 1-1

The South Coast AQMD provided a formal notice of the proposed project to all California Native American Tribes that either requested to be on the Native American Heritage Commission's (NAHC) notification list or South Coast AQMD's mailing list per Public Resources Code Section 21080.3.1(b)(1) and a notice of the proposed project was provided to the commenter. These notices provide an opportunity for California Native American Tribes to request a consultation with the South Coast AQMD if potentially significant adverse impacts to Tribal cultural resources are identified. The Final SEA for the proposed project did not identify any potentially significant adverse impacts to Tribal cultural resources and the commenter requests no further consultation, unless additional information or the scope of work changes. Further, the South Coast AQMD did not receive any consultation requests from any California Native American Tribes, including the commenter, relative to the proposed project. Since this comment does not raise any issues relative to Tribal cultural resources during the comment period for the Draft SEA, no further response is necessary under CEQA.

COMMENT LETTER #2 – San Manuel Band of Mission Indians, September 20, 2021 (p. 1 of 2)

Kevin Ni

From:	Ryan Nordness <Ryan.Nordness@sanmanuel-nsn.gov>
Sent:	Monday, September 20, 2021 2:31 PM
To:	Sarady Ka
Cc:	Kevin Ni
Subject:	RE: CEQA Notice for Emissions of Nitrogen from Petroleum Refineries and related options.

Hello Sarady,

Thank you for contacting the San Manuel Band of Mission Indians (SMBMI) regarding the above referenced project. SMBMI appreciates the opportunity to review the project documentation, which was received by our Cultural Resources Management Department on September 14th, pursuant to CEQA (as amended, 2015) and CA PRC 21080.3.1. The proposed project area exists within Serrano ancestral territory and, therefore, is of interest to the Tribe. However, due to the nature and location of the proposed project, and given the CRM Department's present state of knowledge, SMBMI does not have any concerns with the project's implementation, as planned, at this time. As a result, SMBMI requests that the following language be made a part of the project/permit/plan conditions:

CUL MMs

1. In the event that cultural resources are discovered during project activities, all work in the immediate vicinity of the find (within a 60-foot buffer) shall cease and a qualified archaeologist meeting Secretary of Interior standards shall be hired to assess the find. Work on the other portions of the project outside of the buffered area may continue during this assessment period. Additionally, the San Manuel Band of Mission Indians Cultural Resources Department (SMBMI) shall be contacted, as detailed within TCR-1, regarding any pre-contact and/or historic-era finds and be provided information after the archaeologist makes his/her initial assessment of the nature of the find, so as to provide Tribal input with regards to significance and treatment.

2. If significant pre-contact and/or historic-era cultural resources, as defined by CEQA (as amended, 2015), are discovered and avoidance cannot be ensured, the archaeologist shall develop a Monitoring and Treatment Plan, the drafts of which shall be provided to SMBMI for review and comment, as detailed within TCR-1. The archaeologist shall monitor the remainder of the project and implement the Plan accordingly. 2-1

3. If human remains or funerary objects are encountered during any activities associated with the project, work in the immediate vicinity (within a 100-foot buffer of the find) shall cease and the County Coroner shall be contacted pursuant to State Health and Safety Code §7050.5 and that code enforced for the duration of the project.

TCR MMs

1. The San Manuel Band of Mission Indians Cultural Resources Department (SMBMI) shall be contacted, as detailed in CR-1, of any pre-contact and/or historic-era cultural resources discovered during project implementation, and be provided information regarding the nature of the find, so as to provide Tribal input with regards to significance and treatment. Should the find be deemed significant, as defined by CEQA (as amended, 2015), a cultural resources Monitoring and Treatment Plan shall be created by the archaeologist, in coordination with SMBMI, and all subsequent finds shall be subject to this Plan. This Plan shall allow for a monitor to be present that represents SMBMI for the remainder of the project, should SMBMI elect to place a monitor on-site.

2. Any and all archaeological/cultural documents created as a part of the project (isolate records, site records, survey reports, testing reports, etc.) shall be supplied to the applicant and Lead Agency for dissemination to

COMMENT LETTER #2 – San Manuel Band of Mission Indians, September 20, 2021 (p. 2 of 2)

SMBMI. The Lead Agency and/or applicant shall, in good faith, consult with SMBMI throughout the life of the project.

Note: San Manuel Band of Mission Indians realizes that there may be additional tribes claiming cultural affiliation to the area; however, San Manuel Band of Mission Indians can only speak for itself. The Tribe has no objection if the agency, developer, and/or archaeologist wishes to consult with other tribes in addition to SMBMI and if the Lead Agency wishes to revise the conditions to recognize additional tribes.

Please provide the final copy of the project/permit/plan conditions so that SMBMI may review the included language. This communication concludes SMBMI's input on this project, at this time, and no additional consultation pursuant to CEQA is required unless there is an unanticipated discovery of cultural resources during project implementation. If you should have any further questions with regard to this matter, please do not hesitate to contact me at your convenience, as I will be your Point of Contact (POC) for SMBMI with respect to this project. 2-1 cont'

Respectfully,
Ryan Nordness

RESPONSE TO COMMENT LETTER #2 – San Manuel Band of Mission Indians, September 20, 2021

Response 2-1

South Coast AQMD provided a formal notice of the proposed project to all California Native American Tribes that requested to be on the NAHC's notification list per Public Resources Code Section 21080.3.1(b)(1) and this list included the San Manuel Band of Mission Indians. Furthermore, the provisions of CEQA, Public Resources Code Sections 21080.3.1 et seq. (also known as AB 52), requires meaningful consultation with California Native American Tribes on potential impacts to tribal cultural resources, as defined in Public Resources Code Section 21074. The comment that the San Manuel Band of Mission Indians requests no further consultation on the proposed project is noted.

The Final SEA contains a programmatic review of the proposed project and relies on the best information available at the time of publication to evaluate the potential impacts to all of the environmental topic areas, including cultural resources and Tribal cultural resources.

As explained in Subchapter 4.5, this Final SEA tiers off of the December 2015 Final PEA for NOx RECLAIM which previously analyzed cultural and Tribal cultural resource impacts associated with installing new SCRs with associated ammonia storage tanks, upgrading existing SCRs, installing new LoTOx™ with and without WGSs, installing new UltraCatTM with DGS and concluded that no impacts would occur at any of the affected facilities since the construction-related activities are expected to be confined within the existing footprint of the affected facilities that have been fully developed and paved such that no physical changes to the environment which may disturb paleontological, archaeological, or historical resources would occur. For the same reason, the analysis in the December 2015 Final PEA for NOx RECLAIM also concluded that no site, feature, place, cultural landscape, sacred place, or object with cultural value to a California Native American Tribe would be disturbed. The proposed project as evaluated in this Final SEA is expected to result in an incremental increase in the number of new SCRs with associated ammonia storage tanks to be installed, and the number of existing SCRs to be upgraded. Other incremental changes that may result from implementing the proposed project involve the replacement of existing burners with ULNBs. The proposed project will affect the same nine refinery-sector facilities as previously analyzed in December 2015 Final PEA for NOx RECLAIM plus an additional seven refinery facilities, which are also industrial facilities expected to be devoid of the same types of cultural and tribal cultural resources. Therefore, the previous conclusion of no impact to cultural and tribal cultural resource resources reached in the December 2015 Final PEA for NOx RECLAIM will continue to apply to the proposed project.

Since no significant cultural and tribal cultural resource impacts, mitigation measures are not required. For this reason, the recommended mitigation measures for cultural and tribal cultural resources in this comment have been not been included in this SEA or in the Mitigation, Monitoring and Reporting Plan (see Attachment 1 to the Resolution).

Due to the programmatic nature of the CEQA analysis in this SEA, details about the actual construction activities that operators of individual facilities may undertake to comply with the proposed project are not available. Before construction can commence, each facility proposing to make physical modifications requiring construction would need to obtain city or county planning department approvals and would be subject to project-level review, including notification and separate tribal consultation under AB 52, as applicable, to address site-specific requests identified by the tribes, including the San Manuel Band of Mission Indians, as applicable.

Construction resulting from the proposed project at individual facilities would need to obtain city or county planning department approvals prior to commencement of any construction activities and would be subject to project-level review, including separate tribal consultation under AB 52, as applicable, to address site-specific requests identified by the tribes and appropriate mitigation measures such as the ones suggested in the comment.

Although the facilities affected by the proposed project are located on previously disturbed sites where there is little likelihood of remaining identifiable artifacts, it is possible, that cultural or archaeological resources may nevertheless be discovered. While the likelihood of encountering cultural resources is low, there is still a potential that additional buried archaeological resources may exist. Any such impact would be eliminated by using standard construction practices and complying with state law including Public Resources Code Section 21083.2 and CEQA Guidelines Section 15064.5, which require the following, in the event that unexpected sub-surface resources were encountered:

- Conduct a cultural resources orientation for construction workers involved in excavation activities. This orientation will show the workers how to identify the kinds of cultural resources that might be encountered, and what steps to take if this occurred;

- Monitoring of subsurface earth disturbance by a professional archaeologist and a representative of the tribe with tribal cultural resources in the area, if cultural resources are exposed during construction;

- Provide the archaeological monitor with the authority to temporarily halt or redirect earth disturbance work in the vicinity of cultural resources exposed during construction, so the find can be evaluated and mitigated as appropriate; and,

- As required by State law in Public Resources Code Sections 5097.94 and 5097.98, prevent further disturbance if human remains are unearthed, until the County Coroner has made the necessary findings with respect to origin and disposition, and the Native American Heritage Commission has been notified if the remains are determined to be of Native American descent.

COMMENT LETTER #3 – Santa Ynez Band of Chumash Indians, October 11, 2021 (p. 1 of 1)

SANTA YNEZ CHUMASH TRIBAL ELDERS COUNCIL
TO PROTECT AND PRESERVE TRIBAL ANCESTRY, TRADITIONS AND CULTURE

Santa Ynez Band of Chumash Indians
Tribal Elders' Council
P.O. Box 517 ◆ Santa Ynez ◆ CA ◆ 93460
Phone: (805)688-7997 ◆ Fax: (805)688-9578 ◆ Email: elders@santaynezchuhmash.org

October 11, 2021

South Coast Air Quality Management District

21865 Copley Drive

Diamond Bar, CA 91765-4178

Att.: Kevin Ni

Re: Proposed Adoption of, or Amendment the Rules and Regulations SCAQMD and proposed submission into the State Implementation Plan

Dear Mr. Ni:

Thank you for contacting the Tribal Elders' Council for the Santa Ynez Band of Chumash Indians.

At this time, the Elders' Council requests no further consultation on this project; however, if supplementary literature reveals additional information, or if the scope of the work changes, we kindly ask to be notified. 3-1

If you decide to have the presence of a Native American monitor in place during ground disturbance to assure that any cultural items unearthed be identified as quickly as possible, please contact our office or Chumash of the project area.

Thank you for remembering that at one time our ancestors walked this sacred land.

Sincerely Yours,

Kelsie A. Shroll

Kelsie Shroll
Administrative Assistant | Elders' Council and Culture Department
Santa Ynez Band of Chumash Indians | Tribal Hall
(805) 688-7997 ext. 7516
kshroll@santaynezchumash.org

RESPONSE TO COMMENT LETTER #3 – Santa Ynez Band of Chumash Indians, October 11, 2021

Response 3-1

Comment letter #3 was submitted in response to the Notice of Public Hearing for the proposed project which was sent to interested parties on October 6, 2021 and appears to be a duplicate of Comment Letter #1. See Response to Comment Letter #1.

COMMENT LETTER #4 – Tesoro Refining & Marketing Company LLC, October 19. 2021 (p. 1 of 10)

Tesoro Refining & Marketing Company LLC
A subsidiary of Marathon Petroleum Corporation

Los Angeles Refinery
2350 E. 223rd Street
Carson, California 90810
310-816-8100

October 19, 2021

VIA Certified Mail and eMail (*bradlein@aqmd.gov*)
7019 2280 0001 9253 2360
Return Receipt Requested

Barbara Radlein
Program Supervisor, CEQA
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Comments on Draft Subsequent Environmental Assessment for Proposed Rule (PR) 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations, PR 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations, Proposed Amended Rule (PAR) 1304 – Exemptions, PAR 2005 – New Source Review for RECLAIM, and Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries (Dated September 1, 2021)

Dear Ms. Radlein:

On behalf of Tesoro Refining & Marketing Company LLC, a wholly owned subsidiary of Marathon Petroleum Corporation (collectively, "MPC"), MPC appreciates this opportunity to provide South Coast Air Quality Management District (SCAQMD) with comments on SCAQMD's Draft Subsequent Environmental Assessment (Draft SEA) that was released on September3, 2021.[1] The Draft SEA was developed pursuant to the California Environmental Quality Act (CEQA) and evaluates all of the potential adverse environmental impacts that could result from implementing Proposed Rule (PR) 1109.1, PR 429.1, Proposed Amended Rule (PAR) 1304, PAR 2005 and Proposed Rescinded Rule 1109 (Project). Throughout the rulemaking process, MPC staff has continued to be active participants in PR 1109.1 working group meetings and discussions with SCAQMD staff. 4-1

As SCAQMD is aware, in order to meet the nitrogen oxide (NOx) emissions reduction requirements in PR 1109.1 within the timelines prescribed under the rule, it will be important that MPC is able to implement the necessary compliance projects at its Los Angeles Refinery (LAR) in a timely manner. To meet PR 1109.1's timelines for implementing MPC's compliance projects, including equipment replacement projects, necessary to comply with the requirements of PR 1109.1, MPC wishes to rely on SCAQMD's SEA's analysis of potential impacts when applying for Permits to Construct from SCAQMD and other permits and approvals for the potential compliance projects that will be necessary to comply with the rule. Therefore, MPC is providing this set of comments as a supplement to MPC's previous

[1] http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2021/pr-1109-1-draft-sea.pdf?sfvrsn=6

COMMENT LETTER #4 – Tesoro Refining & Marketing Company LLC, October 19, 2021 (p. 2 of 10)

Letter to Ms. Barbara Radlein
October 19, 2021
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Page 2

CEQA-related comment letter that was submitted to SCAQMD on December 22, 2020, in order to clarify several areas SCAQMD reviewed as part of its CEQA environmental analysis. 4-1 cont'd

1. **Clarify that ammonium sulfate emissions associated with operating Selective Catalytic Reduction (SCR) controls on gas-fired combustion equipment have been addressed.**

   The Draft SEA discusses the impacts from ammonium sulfate emissions in several sections and concludes that the cumulative air quality impacts from implementing the Project will be less than significant increases of PM10 and PM2.5 emissions during the operational phase of the Project. To confirm that SCAQMD's analysis clearly addressed PM10 and PM2.5 emissions increases associated with ammonium sulfate emissions emitted directly from equipment that is being replaced and/or retrofitted with NOx post-combustion control equipment necessary to comply with PR 1109.1, MPC requests the first paragraph on page 4.2-52 (copied below) of the Draft SEA be revised as follows: 4-2

   > *In an SCR system, the ammonia or urea is injected into the flue gas stream and reacts with NOx to form elemental nitrogen (N2) and water in the cleaned exhaust gas. ~~A small~~ Some amount of unreacted ammonia may react with SOx in the refinery fuel gas that is burned by the boiler or process heater to form ammonium sulfate that is emitted directly from the unit, or ~~(ammonia slip)~~ may pass through as ammonia slip.*
   >
   > ...
   >
   > *The overall decrease in annual PM2.5 concentration would occur as long as 14 tons per day of NOx emissions would be reduced, even if there was an uptick in the regional concentration of PM2.5 emissions due to ammonia slip and ammonium sulfate.*

2. **Incorporate MPC's updated list of potential compliance projects at LAR and clarify affected equipment includes replaced and retrofitted units.**

   MPC's December 22, 2020 CEQA letter included a catalog of potential compliance projects MPC initially anticipated that it would need to implement at LAR in order to comply with a future developed PR 1109.1. Since this evaluation, SCAQMD has issued several iterations of proposed draft language for PR 1109.1 with its most recent 30-Day draft PR 1109.1 language issued October 6, 2021. Based on the proposed draft rule language in PR 1109.1, MPC has updated its initial December 2020 list of potential compliance projects to include all of the potential equipment modification/replacement projects that may be required at LAR to comply with the current draft PR 1109.1. (See Attachment 1 for updated list of potential compliance projects and equipment modification/replacement projects). 4-3

   As such, MPC requests that SCAQMD reference and incorporate MPC's updated list of potential compliance projects that is provided in Attachment 1. This is a conservative account of what potential compliance projects may be needed at LAR and represents the maximum number of potential equipment modifications and replacements. For your reference, MPC will submit supporting information for Attachment 1 under separate cover. It should be noted that MPC reserves the right to supplement or amend this list of potential compliance projects if any

COMMENT LETTER #4 – Tesoro Refining & Marketing Company LLC, October 19, 2021 (p. 3 of 10)

Letter to Ms. Barbara Radlein
October 19, 2021
PR 1109.1 CEQA
Page 3

refinements are made to the draft PR1109.1 language that is currently contained in the 30-day package that was issued on October 6, 2021.

In addition to updating the SEA to incorporate MPC's updated list of potential compliance projects and equipment modification/replacement projects at LAR, the SEA should be updated to clearly identify under Section 2.5 that the affected equipment analyzed by SCAQMD includes units that will be retrofitted with technology and units that will be replaced. Since PR 1109.1 and PAR 1304 both specifically provide for replacement of basic equipment as a compliance mechanism along with installation of emissions controls (i.e., retrofitting), MPC requests that SCAQMD clarify in its SEA that both replaced and retrofitted units were analyzed under this CEQA document. For reference, MPC suggests the following revision to the last paragraph under Section 2.5 Summary of Affected Equipment on page 2-41: 4-3 (cont'd)

> *Of these 284 pieces of equipment, staff estimates 74 units will be retrofit with new SCRs, 16 SCRs could be upgraded, and 76 units expected to be retrofitted with ULNB. In lieu of SCR, two pieces of equipment may be retrofit with a LoTOx™ wet gas scrubber or Ultracat dry gas scrubber. In addition, staff estimates 52 boilers and process heaters will be retrofit with emerging LNB technology at time of burner replacement at a future date. Instead of retrofitting existing units with emission controls to comply with PR 1109.1, some facilities may replace existing units with new units (also with new emissions controls) that serve the same purpose. As part of any potential compliance project, facilities may need to replace and/or upgrade existing process equipment and/or utilities, including potentially installing fuel gas sulfur treatment (if required).*

3. Correct the tables and discussion of units with accurate number of existing NOx controls. 4-4

Beginning on page 4.2-22 in the Draft SEA, the discussion of Facility 1 should be corrected as follows:

Table 4.2-21
Facility 1: Existing NOx Controls

Total Number of Equipment per Category	*Equipment with LNBs*	*Equipment with ULNBs*	*Equipment with SCR*	*Equipment with SCR + LNBs*	*Equipment without NOx control*
30 Heaters	~~19~~24	~~4~~2	~~2~~0	~~2~~4	~~3~~0
2 SRU/TGs	*2*	-	-	-	-
1 FCCU	-	-	*1*	-	-
4 Gas Turbines with Duct Burners	-	-	*4*	-	-

Beginning at the end of page 4.2-22 and continuing onto page 4.2-23, the discussion of previous projects at Facility 1 should be corrected as follows:

> *Construction and operational impacts associated with 3) upgrading one existing SCR for one gas turbine with a duct burner at Facility 1 were also previously analyzed in the*

COMMENT LETTER #4 – Tesoro Refining & Marketing Company LLC, October 19, 2021 (p. 4 of 10)

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> *December 2015 Final PEA for NOx RECLAIM. After the NOx RECLAIM program was amended in 2015, operators at Facility 1 installed ~~four~~ one new SCRs ~~with associated aqueous ammonia storage tanks~~ for ~~four~~ one heaters.*

The subsequent discussion on pages 4.2-23 through 4.2-24 should be updated to reflect the installation of one SCR and one ammonia storage tank since 2015.

Beginning on page 4.2-27 in the Draft SEA, the discussion of Facility 3 should be corrected as follows:

Table 4.2-28
Facility 3: Existing NOx Controls

Total Number of Equipment per Category	*Equipment with LNBs*	*Equipment with ULNBs*	*Equipment with SCR*	*Equipment with SCR + LNBs*	*Equipment without NOx control*
2 Boilers	-2	-	-	-	~~2~~-
2 SRU/TGs	~~1~~-	-	-	-	~~1~~2

> *Under the proposed project, ~~only one~~ both boilers ~~is~~ are expected to need ~~a~~ new SCRs but ~~it~~ they will also be expected to undergo burner replacement with ULNBs. Due to the new SCR for ~~this~~ one boiler having been previously analyzed in the December 2015 Final PEA for NOx RECLAIM, the analysis for ~~this~~ these boilers in this SEA only needs to include the environmental impacts associated with replacing the existing burners with ULNBs and installing one new SCR.*

The subsequent discussion on pages 4.2-27 and 4.2-28 should be updated to reflect the installation of SCR and a new ULNB on each boiler.

Beginning on page 4.2-28 in the Draft SEA, the discussion of Facility 4 should be corrected as follows:

> *Facility 4 operates the following combustion equipment which will be subject to PR 1109.1: ~~31~~28 heaters and boilers, and two gas turbines. Tables 4.2-31 and 4.2-32 summarize the existing NOx air pollution control equipment and possible methods for achieving NOx emission reductions.*

4-4 cont'd

Table 4.2-28
Facility 4: Existing NOx Controls

Total Number of Equipment per Category	*Equipment with LNBs*	*Equipment with ULNBs*	*Equipment with SCR*	*Equipment with SCR + LNBs*	*Equipment without NOx control*
28 Heaters/Boilers	~~9~~6	-	~~2~~3	13	~~7~~6
2 SRU/TGs	-	-	2	-	-

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> *For Facility 4, the December 2015 Final PEA for NOx RECLAIM previously analyzed construction and operational impacts associated with installing: 1) six new SCRs with six aqueous ammonia storage tanks for six heaters/boilers; and 2) one LoTOxTM with WGS for one FCCU. Also, construction and operational impacts associated with 3) upgrading one existing SCR for one gas turbine with duct burner at Facility 4 was previously analyzed in December 2015 Final PEA for NOx RECLAIM. After the NOx RECLAIM Program was amended in 2015, operators of Facility 4 did not install any air pollution control equipment but the FCCU <u>and three associated heaters were</u> ~~was~~ shut down.* 4-4 cont'd

4. **Clarify the application of PAR 1304 to compliance projects for consistency with the Draft Staff Report for PAR 1304.**

As discussed beginning on page 2-3 in the Draft Staff Report for PAR 1304 – Exemptions[2], the proposed provision under PAR 1304 has the Best Available Control Technology (BACT) exemption evaluated separately from federal New Sources Review (NSR) and allows the use of the BACT exemption for compliance projects that replace equipment in different source categories so long as the definition for a "replacement unit" under federal NSR and federal guidance are used for the purposes of determining if federal NSR applies to the compliance project. However, SCAQMD's evaluation for the ninth Area of Controversy related to "Criteria for equipment replacements allowed to use the PAR 1304 BACT exemption" (#9) in Table 1.4-1 of the Draft SEA is contrary to the language in PAR 1304 and the agency's discussion in its Draft Staff Report. As such, MPC requests that SCAQMD update its evaluation under #9 of Table 1.4-1 so that it matches its analysis and conclusions in the Draft Staff Report, and strike the final two sentences under #9 in Table 1.4-1 on page 1-21 as follows: 4-5

> *The federal NSR definition for a replacement requires that replacing a unit with a unit from a different source category that serves the same purpose would need to have the same basic design parameters. ~~Units from different source categories, such as a turbine and a boiler, would not have the same basic design parameters. The federal NSR definition for a replacement is used as the replacement criteria for the PAR 1304 BACT exemption, since under federal NSR, for a replacement unit, the baseline emissions are the actual emissions of the existing unit being replaced rather than a zero baseline if considered a new unit.~~*

5. **Revise the discussion of risk from aqueous ammonia to acknowledge that facilities that currently use 29 percent aqueous ammonia may continue to use 29 percent aqueous ammonia for newly installed or modified equipment. Existing equipment requiring modification that currently uses ammonia would continue to use the same type of ammonia as currently permitted.** 4-6

[2] http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regx111/draft-staff-report-par-1304-and-2005.pdf?sfvrsn=6

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The Draft SEA assesses risk associated with the use of 19 percent by weight aqueous ammonia. As provided in our previous December 22, 2020 CEQA comment letter, MPC's LAR currently uses 29 percent aqueous ammonia and would like to use 29 percent aqueous ammonia for any potential compliance project to simplify procurement and management of aqueous ammonia. For existing equipment with minor SCR modifications required for compliance with PR 1109.1, the type and concentration of ammonia would not change. Since LAR currently uses 29 percent aqueous ammonia, continued use would not result in increased hazard impact relative to the current baseline condition. Furthermore, as previously stated in our December 22, 2020 letter, the use of 29 percent aqueous ammonia results in fewer truck trips and does not change the hazard radius analysis when compared to the use of 19 percent aqueous ammonia. 4-6 cont'd

In addition, the SCAQMD has allowed the use of 29 percent aqueous ammonia in recent projects. For example, the *Addendum to the April 2007 Final Mitigated Negative Declaration for Southern California Edison: Center Peaker Project, Norwalk (February 2017)*[3] and the *Addendum to the April 2007 Final Mitigated Negative Declaration for Southern California Edison: Mira Loma Peaker Project, Ontario*[4] both evaluated projects that included increasing the concentration of aqueous ammonia used at a facility from 19 percent to 29 percent and concluded that use of 29 percent aqueous ammonia did not pose a significant hazard impact.

6. **Include the construction emissions associated with the use of emerging technologies on process heaters.**

   SCAQMD states on page 4.1-5 of the Draft SEA that construction emissions were not analyzed for facilities' compliance projects that may use emerging technologies in the future. Currently the most likely method of complying with the use of emerging technologies will be to install new burners that are not yet commercially available. Thus, the construction emissions associated with the use of emerging technologies for complying with PR 1109.1 should be estimated based on burner replacements. 4-7

7. **Update the construction emission greenhouse gas (GHG) estimates for consistency between the Appendix and the body of the CEQA document.**

   As MPC representatives discussed with the staff of SCAQMD on October 6, 2021, the detailed GHG construction emissions are not consistent between the CalEEMod runs in Appendix C to the Draft SEA and when totaled by facility as described in the text of the Draft SEA document. SCAQMD should update its CEQA document so that the emission totals presented in the text of the Draft SEA are consistent with the calculations in Appendix C to the Draft SEA. 4-8

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[3] http://www.aqmd.gov/docs/default-source/ceqa/documents/permit-projects/2017/CenterAddendum_Final.pdf?sfvrsn=4
[4] http://www.aqmd.gov/docs/default-source/ceqa/documents/permit-projects/2019/mira-loma-addendum_final.pdf?sfvrsn=6

COMMENT LETTER #4 – Tesoro Refining & Marketing Company LLC, October 19, 2021 (p. 7 of 10)

Letter to Ms. Barbara Radlein
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8. Update construction emission estimates to reflect the use of Tier 4 equipment.

As MPC representatives have previously discussed with the staff of SCAQMD, the construction emission estimates provided by MPC in May 2021 were calculated using unmitigated construction equipment emission factors. MPC has subsequently updated its emissions calculations to reflect the mitigation that will be required according to the Draft SEA. Accordingly, MPC requests that SCAQMD update Table 4.2-23 of the Draft SEA with MPC's updated mitigated construction emissions. Incorporating MPC's updated mitigated construction emissions will provide a more consistent comparison to the SCAQMD CalEEMod mitigated construction emission estimates. For your reference, MPC is providing these updated emission calculations by electronic email. 4-9

Conclusion

MPC appreciates the opportunity to provide comments and additional information to support SCAQMD's CEQA evaluation for PR 1109.1. Because MPC intends to rely upon this evaluation when implementing its compliance projects at LAR in order to comply with PR 1109.1, we would appreciate SCAQMD staff's efforts to ensure that all of MPC's potential compliance projects and equipment modification/replacement projects and potential impacts from compliance with PR1109.1 are evaluated and addressed in the SEA. 4-10

Please note that in submitting this letter, MPC reserves the right to supplement its comments as it deems necessary, especially if additional or different information is made available to the public regarding the Proposed Rule 1109.1 rulemaking process or Proposed Rule 1109.1 is refined in any way.
Please call Shawn Tieu at (310) 847-5274 if you have any questions or comments regarding the enclosed package.

Sincerely,

Denis Kurt

LAR Environmental, Safety & Security (ESS) Manager

cc: SCAQMD
Susan Nakamura – Assistant Deputy Executive Officer
Michael Krause – Planning and Rules Manager
Kevin Ni – Air Quality Engineer II

COMMENT LETTER #4 – Tesoro Refining & Marketing Company LLC, October 19, 2021 (p. 8 of 10)

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October 19, 2021
PR 1109.1 CEQA
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ccc: 2021-10-19 MPC Comment Letter Draft SEA for SCAQMD PR 1109.1
Ruth Cade, MPC RE
Chris Drechsel, MPC RE
Denis Kurt, MPC LAR
Brad Levi, MPC LAR
Robert Nguyen, MPC LAR
Robin Schott, MPC LAR
Vanessa Vail, MPC LAW

COMMENT LETTER #4 – Tesoro Refining & Marketing Company LLC, October 19, 2021 (p. 9 of 10)

Attachment 1

Updated List of MPC's Potential Compliance Projects for PR 1109.1

COMMENT LETTER #4 – Tesoro Refining & Marketing Company LLC, October 19, 2021 (p. 10 of 10)

Table 4.2-22
Facility 1: Potential Methods to Achieve NOx BARCT

Number of Equipment	Category	New Burner	New SCR	Burner + SCR	SCR Upgrade	Boiler/Heater Replacement + SCR	No Change
30	Heaters/Boilers	12	12	1	0	2	3
2	SRU/TGs	1	0	0	0	0	1
1	FCCU	0	0	0	0	0	1
4	Gas Turbine	0	0	0	0	0	4

Table 4.2-29
Facility 3: Potential Methods to Achieve NOx BARCT

Number of Equipment	Category	New Burner	New SCR	Burner + SCR	SCR Upgrade	Boiler/Heater Replacement + SCR	No Change
2	Boilers	0	2	0	0	0	0
2	SRU/TGs	2	0	0	0	0	0

Table 4.2-32
Facility 4: Potential Methods to Achieve NOx BARCT

Number of Equipment	Category	New Burner	New SCR	Burner + SCR	SCR Upgrade	Boiler/Heater Replacement + SCR	No Change
28	Heaters/Boilers	1	9	2	0	7	2
2	Gas Turbine	0	0	0	2	0	0

RESPONSE TO COMMENT LETTER #4 – Tesoro Refining & Marketing Company LLC, October 19, 2021

Response 4-1

South Coast AQMD staff appreciates the commenter's input and participation throughout the development of the proposed project. As noted by the comment and as explained in Chapter 1 of the SEA, if the South Coast AQMD Governing Board certifies the Final SEA and approves the proposed project, any affected facility operator who proposes to install air pollution control equipment and other components necessary to the installation of that equipment for the purpose of complying with the BARCT emission standards in the proposed project and submits South Coast AQMD permit applications, the individual project would need to undergo a CEQA review to determine if the individual project can rely on the Final SEA or if further CEQA analysis is warranted before any approvals can be granted.

Each of the individual facility's air pollution reduction projects necessary to implement the requirements of PR 1109.1 would likely require at least one permit from South Coast AQMD to construct air pollution control equipment, replace equipment, or both. Also, many of these facility-specific projects are likely to require building permits and possibly other permits from their local agencies. Since it is uncertain exactly which air pollution control technologies will be selected for each facilities air pollution reduction project, it is not feasible to identify all applicable local agency permits that may be required in the future.

Response 4-2

As recommended, the suggested edits have been incorporated into the "Regional PM2.5 Impacts from Ammonia Slip" discussion in Chapter 4, Section 4.2.2 - Potential Air Quality Impacts and Mitigation Measures of the Final SEA.

Response 4-3

The analysis in the Final SEA has been updated to incorporate the commenter's potential compliance projects. In addition, Section 2.5 - Summary of Affected Equipment, has been updated accordingly.

Response 4-4

For Facilities 1 and 4, the Final SEA has been modified to reflect the requested updates to each facility's existing NOx controls and the corresponding discussion as requested. For Facility 3, since the December 2015 Final PEA for NOx RECLAIM analyzed construction emissions associated with the installation of two new SCR with two new ammonia storage tanks for two boilers, the paragraph cited in this comment was deleted from the Final SEA and instead, the following clarifying sentence was added to the discussion following Table 4.2-29: "The potential air quality impacts associated with physical modifications that may occur at Facility 3 in order to achieve the BARCT limits in PR 1109.1 for boilers were previously analyzed in the December 2015 Final PEA for NOx RECLAIM."

Response 4-5

The BACT exemption provided in PAR 1304 can be used for situations where a unit will be replaced with a new unit from a different source category (e.g., a boiler for a turbine). If the new unit is installed to meet a NOx BARCT limit and serves the same purpose, then the BACT exemption will not be restricted to require the new unit to be from the same source category. Table 1.4-1, Item 9 in Chapter 1 of the Final SEA has been updated to reflect this understanding.

Response 4-6

The following clarifications regarding the South Coast AQMD's policy for ammonia use in air pollution control equipment (see new language in **bold**) have been included in the Final SEA, Chapter 4, Subchapter 4.2 – Air Quality and Greenhouse Gas Emissions, Section 4.2.2.2: Project-Specific Air Quality Impacts During Operation, and Subchapter 4.3 – Hazards and Hazardous Materials, Section 4.3.2.3 – Project Specific Impacts:

> *For any new construction of air pollution control equipment that utilizes ammonia, such as SCR technology, current South Coast AQMD policy does not allow the use of ~~anhydrous~~ ammonia* ***at concentrations greater than 19% for new construction of a storage tank if the quantity capable of being stored is greater than 500 pounds or if the quantity is less than 500 pounds but there is a risk for an offsite consequence in the event of a tank failure. Existing storage tanks containing ammonia at concentrations greater than 19% may be used to service new installations of air pollution control equipment.*** *To minimize the hazards associated with the use of ammonia, aqueous ammonia at a concentration of no more than 19 percent by weight (19% aqueous ammonia) is typically required as a permit condition associated with the installation of new SCR equipment. This policy is why the December 2015 Final PEA for NOx RECLAIM assumed that all ammonia utilized for new SCRs and UltraCat™ DGSs, would be 19% aqueous ammonia. Moreover, for the analysis in this SEA, in accordance with South Coast AQMD policy, the new SCRs are assumed to utilize 19% aqueous ammonia. However, any existing SCR which may undergo an upgrade would be expected to continue to utilize the same type of ammonia (e.g., anhydrous, 19% aqueous ammonia or some other concentration) and about the same quantity as it is currently using. The analysis also assumes that the existing ammonia storage tank for SCR upgrades will continue to provide the ammonia needed to continue operating the existing SCRs, without requiring any physical modifications.* ***In the event that existing ammonia tanks are utilized for new installations of SCR, construction impacts would be less than assumed since the analysis assumed one new tank for each new SCR. Further, depending on the number of additional SCRs that would need to receive ammonia from an existing ammonia storage tank, the ammonia throughput limit on the permit may need to be revised. Increases of ammonia throughput for an existing tank would not be expected to change the existing risk associated with an offsite consequence in the event of a tank rupture***

Response 4-7

South Coast AQMD staff recognizes the potential that emerging technology may have to achieve future reductions of NOx emissions, once it is fully mature. Unfortunately, emerging technology is not expected to be available for about 10 years which means that any construction activities and the associated construction emissions for emerging technology are not expected to overlap with the construction projects that may be implemented as soon as next year. The analysis in Chapter 4, Section 4.2.2.3: Individual Facility Analyses for Construction and Operation, provides estimates of construction emissions based on a worst-case peak day, prior to when emerging technology would be viable. For this reason, the construction analysis in the Final SEA has not been updated to incorporate the peak daily construction emissions of criteria pollutants that may be associated with installing emerging technology. While construction activities typically occur over a relatively short-term such that the potential increase in criteria air pollutants during construction will disperse, GHG emissions accumulate over time. For this reason, the construction estimates for GHG emissions associated with burner replacements have been updated in Chapter 4 of the Final SEA (see Section 4.2.5 - Greenhouse Gas Impacts and Mitigation Measures) to account for the construction GHG emissions that may occur in the event that emerging technology is installed in the future.

Response 4-8
To remedy the inconsistency, the GHG emission estimates during construction as presented in Chapter 4, Tables 4.2-64a and 4.2-64b and in Appendix C of the Final SEA have been updated. The updated GHG emission estimates reflect fewer overall GHG emissions relative to the quantity originally presented in the Draft SEA but remain significant. Thus, no change to the overall conclusion for GHG emissions is necessary.

Response 4-9
Tables 4.2-23 and 4.2-33 have been updated to reflect the revised emission estimates which apply adjustments to reflect mitigated (fewer) emissions from being required to use equipment rated as "Tier 4 Final" as mitigation. The corresponding facility-specific construction emissions have also been updated with these values.

Response 4-10
South Coast AQMD staff appreciates the commenter's input and participation throughout the development of the proposed project. Response 4-1 addresses how facilities may be able to rely on this SEA when submitting applications for individual projects. South Coast AQMD staff also recognizes that the commenter may take the opportunity to provide additional comments regarding the proposed project.

COMMENT LETTER #5 – Torrance Refining Company, October 19, 2021 (p. 1 of 2)

Torrance Refining Company

Torrance Refining Company LLC
3700 W. 190th Street
Torrance, CA 90504
www.pbfenergy.com

October 19, 2021

VIA E-MAIL: bradlein@aqmd.gov

Barbara Radlein
Program Supervisor, CEQA
Planning, Rule Development & Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Comments on Draft Subsequent Environmental Assessment for Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR 1109.1), Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations (PR 429.1), Proposed Amended Rule 1304 – Exemptions (PAR 1304), Proposed Amended Rule 2005 – New Source Review for RECLAIM (PAR 2005), and Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries released to the Public on Friday, September 3, 2021

Dear Ms. Radlein,

Torrance Refining Company LLC ("TORC") appreciates the opportunity to provide comments on the above referenced Draft Subsequent Environmental Assessment ("Draft SEA"). As explained in the Draft SEA, among the intended uses of the document, which TORC concurs with, is to support future discretionary actions of the South Coast Air Quality Management District's ("District"), other state and local agencies, and cities and counties that might be required to issue permits and other approvals to facilities, such as TORC's Refinery, that are subject to PR 1109.1 in order to implement projects necessary to comply with the rule. 5-1

In further commenting on the Draft SEA, TORC references its prior comments, submitted to the District on November 20, 2020, December 14, 2020, January 27, 2021, two letters on April 16, 2021, June 21, 2021, August 4, 2021, and September 17, 2021. TORC also incorporates by reference those made by the Western States Petroleum Association regarding the Draft SEA and the development of PR 1109.1, PR 429.1, PAR 1304, PAR 2005, and proposed rescinded Rule 1109. 5-2

Please note that in submitting this letter, TORC reserves the right to supplement its comments as it deems necessary, especially if additional or different information is made available to the public regarding the Draft SEA and the development of PR 1109.1, PR 429.1, PAR 1304, PAR 2005, and proposed rescinded Rule 1109. 5-3

COMMENT LETTER #5 – Torrance Refining Company, October 19, 2021 (p. 2 of 2)

Barbara Radlein, October 19, 2021 Page 2 — *Re: South Coast Air Quality Management District's Draft SEA for PR 1109.1, PR 429.1, PAR 1304, PAR 2005, and proposed rescinded Rule 1109*

If you have any questions regarding TORC's comments, please call me or John Sakers. Our office phone numbers are 310-212-4500 (Steve) and (310) 212-4292 (John). 5-4

Sincerely,

Steve Steach
Refinery Manager

cc: **District Staff - via e-mail and overnight delivery**

Wayne Nastri	Executive Officer
Sarah Rees, Ph.D.	Deputy Executive Officer
Susan Nakamura	Assistant Deputy Executive Officer
Michael Krause	Planning and Rules Manager
Michael Morris	Planning and Rules Manager

cc: **District Refinery Committee Members - via e-mail and overnight delivery**

Hon. Ben Benoit	Governing Board Chair
Hon. Larry McCallon	Governing Board Member and Refinery Committee Chair
Hon. Lisa Bartlett	Governing Board Member and Refinery Committee Member

cc: **District Governing Board Members - via overnight delivery**

Hon. Joe Buscaino	Governing Board Member
Hon. Michael A. Cacciotti	Governing Board Member
Hon. Vanessa Delgado	Governing Board Vice-Chair
Hon. Gideon Kracov	Governing Board Member
Hon. Shelia Kuehl	Governing Board Member
Hon. Veronica Padilla-Campos	Governing Board Member
Hon. V. Manuel Perez	Governing Board Member
Hon. Rex Richardson	Governing Board Member
Hon. Carlos Rodriguez	Governing Board Member
Hon. Janice Rutherford	Governing Board Member

RESPONSE TO COMMENT LETTER #5 – Torrance Refining Company, October 19, 2021

Response 5-1

As noted by the comment and as explained in Chapter 1 of the SEA, if the South Coast AQMD Governing Board certifies the Final SEA and approves the proposed project, any affected facility operator who proposes to install air pollution control equipment and other components necessary to the installation of that equipment for the purpose of complying with the BARCT emission standards in the proposed project and submits South Coast AQMD permit applications, the individual project would need to undergo a CEQA review to determine if the individual project can rely on the Final SEA or if further CEQA analysis is warranted before any approvals can be granted.

Each of the individual facility's air pollution reduction projects necessary to implement the requirements of PR 1109.1 would likely require at least one permit from South Coast AQMD to construct air pollution control equipment, replace equipment, or both. Also, many of these facility-specific projects are likely to require building permits and possibly other permits from their local agencies. Since it is uncertain exactly which air pollution control technologies will be selected for each facilities air pollution reduction project, it is not feasible to identify all applicable local agency permits that may be required in the future.

Response 5-2

Comment 5-2 seeks to incorporate by reference eight letters submitted to South Coast AQMD regarding the proposed project. The following table delineates each referenced letter by date with a footnote containing a hyperlink to the location on South Coast AQMD's website, and identifies whether the letter contains a CEQA comment or a comment relative to the proposed rule language.

Letters From Torrance Refining Company to South Coast AQMD as Referenced in Comment 5-2	Nature of Comments
1. November 20, 2020	PR 1109.1 (October 23, 2020 version) and CEQA
2. December 14, 2020	PR 1109.1 (November 20, 2020 version)
3. January 27, 2021	Revised RECLAIM Transition Plan (December 10, 2020 version)
4. April 16, 2021	PR 1109.1 Final Report by FERco
5. April 16, 2021	PR 1109.1 Final Report by Norton
6. June 21, 2021	PR 1109.1 (December 24, 2020 version)
7. August 4, 2021	PR 1109.1 (July 21, 2021 version)
8. September 17, 2021	PRs 1109.1 and 429.1, and PAR 1304 (August 20, 2021 version)

Referenced letters are available from South Coast AQMD's website at: http://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book/proposed-rules/rule-1109-1/comment-letters. Specific links to the individual letters are as follows:

Letter 1: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/torc-comment-letter-pr-1109_1_oct-23-2020_final.pdf

Letter 2: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/torc-suppl-comment-letter.pdf

Letter 3: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/torc-comment-letter_-reclaim-transition-plan_-final_-jan-27-2021.pdf

Letter 4: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/4-16-2021-torc-comment-letter-ferco.pdf

Letter 5: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/4-16-2021-torc-comment-letter-norton.pdf

Letter 6: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/comment-letter---torrance-refining-company---062121.pdf

Letter 7: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/080421-rule-1109-1-comment-letter---torc.pdf

Letter 8: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/09-17-2021-torc-comment-ltr-pr-1109-1-75-day-package.pdf

All of the above-referenced letters were submitted prior to the comment period for the Draft SEA and only the letter dated November 20, 2020 mentions CEQA. The comment in following excerpt from November 20, 2020 letter (see pp. 6-7) requests that a programmatic CEQA review be conducted for the proposed project.

A Programmatic CEQA Analysis Must Be Done For PR 1109.1

It is a fundamental principle of CEQA review that environmental effects for the whole of a project must be analyzed together. In this case, the "project" is PR 1109.1 as a whole as required by Control Measure CMB-05 as adopted in the 2016 Air Quality Management Plan ("AQMP"). Yet, staff recently informed TORC representatives on November 10, 2020 during a Zoom meeting that the CEQA review that it is doing to analyze the environmental impacts associated with PR 1109.1's proposed BARCT levels is a Supplemental Environmental Assessments ("SEA") that "tiers off" the December 2015 Final Program Environmental Assessment for RECLAIM, last NOx shave ("2015 RECLAIM NOx Shave PEA"), and the March 2017 Final Program Environmental Impact Report for the 2016 Air Quality Management Plan ("2016 AQMP EIR"). TORC believes that such tiering is a "piecemeal" approach for analyzing the potential environmental impacts for PR 1109.1. ". . . CEQA's requirements 'cannot be avoided by chopping up proposed projects into bite-size pieces which, individually considered, might be found to have no significant effect on the environment or to be only ministerial.' [Fn. omitted.]" *Lincoln Place Tenants Assn. v. City of Los Angeles* (2005) 130 Cal.App.4th 1491,1507 quoting *Plan for Arcadia, Inc. v. City Council of Arcadia* (1974) 42 Cal.App.3d 712, 726.

Notably, tiering off the 2015 RECLAIM NOx Shave PEA is not possible (or valid) because there was no comprehensive analysis of what is currently being proposed by staff in PR 1109.1. For example, the PEA did not analyze: (1) the total number of Refinery equipment components that PR 1109.1 is targeting; (2) the combination of the control technologies (i.e., SCRs and ULNBs) that will be required for almost every Refinery equipment category to meet the currently proposed BARCT levels; (3) the extended implementation schedule with multiple overlapping turnarounds by the Refineries that will be required for almost every Refinery equipment category; and (4) the possibility of installing multiple fuel gas treater projects to address the co-pollutant issue associated with the use of SCR and NH3 injection. This assumes, of course, that it can be proven that the proposed BARCT levels are technologically feasible and cost-effective.

Similarly, tiering off the earlier 2016 AQMP EIR to support PR 1109.1, which seeks to implement RECLAIM sunsetting for the Refining sector is not possible (or valid) because there was no comprehensive analysis in this CEQA document regarding RECLAIM sunsetting, much less for the Refining sector.

Specifically, the problem with tiering off the 2016 AQMP EIR to support the CEQA analysis for PR 1109.1 is that control measure CMB-05 as proposed at the time the 2016 AQMP EIR was prepared did not include a transition out of the RECLAIM program. That language was added well after the CEQA analysis was complete. Furthermore, no additional CEQA analysis was conducted to address the changes to CMB-05.

> Thus, the transition out of the RECLAIM program, which PR 1109.1 seeks to implement for the Refining sector, was not included in the version of CMB-05 presented to the Governing Board as part of the 2016 AQMP. The 2016 AQMP EIR, which was completed in January 2018, did not analyze the transition of the RECLAIM program because that was not prescribed by the CMB-05 measure at that time. Therefore, tiering off of the 2016 AQMP EIR to support PR 1109.1 is not possible since there is no analysis from which to tier.
>
> Staff's attempt to tier without having completed a programmatic analysis of the RECLAIM transition, particularly for PR 1109.1, ignores the fact that RECLAIM is a comprehensive program that includes an assessment of BARCT for all of the RECLAIM equipment categories. RECLAIM was adopted as a whole, a single package, not as a series of individual rules and regulations. There are no separate BARCT regulations in the RECLAIM program. Because RECLAIM allows for BARCT to be implemented on an aggregate basis, all BARCT determinations had to be made together.
>
> Furthermore, all RECLAIM rules are dependent upon one another, and none of these can stand alone. By attempting to analyze the impact of a single RECLAIM rule, i.e., BARCT determination for PR 1109.1, staff is ignoring the interdependency of the program, and thus, improperly disregarding the impacts of the comprehensive program.
>
> Furthermore, RECLAIM is an emissions trading program. It allows facilities to choose to implement specific controls or to purchase emissions credits. A piecemealing analysis does not account for those facilities that have implemented other means to comply with the program and the additional impacts the transition to individual command and control rules may have on these facilities. Additionally, these impacts cannot be captured in a single rule analysis. Rather, staff's piecemealing further ignores the impacts on facilities that are subject to multiple BARCT determinations.
>
> In the absence of a program level CEQA analysis that includes the whole of PR 1109.1, staff's currently proposed segmented analysis tiering off of the 2015 RECLAIM NOx Shave PEA and 2016 AQMP EIR constitutes a classic "piecemealing" that is contrary to the requirements of CEQA. To avoid this, we urge the District to undertake a programmatic and thorough CEQA analysis of all the potentially significant impacts of PR 1109.1.

The Draft SEA specifically addresses this comment in Chapter 1, Section 1.4 – Areas of Controversy (see Table 1.4-1, Item 5). As such, no additional response to the CEQA comment in the November 20, 2020 letter is necessary.

Regarding the other referenced letters, none contain comments relative to CEQA. As such, no additional responses to these referenced letters pertaining to the rule development process are required.

Response 5-3
South Coast AQMD staff recognizes that the commenter may take the opportunity to provide additional comments regarding the proposed project.

Response 5-4
South Coast AQMD staff appreciates the commenter's input and participation throughout the development of the proposed project.

2.2 COMMENT LETTERS RECEIVED AFTER THE CLOSE OF THE PUBLIC REVIEW AND COMMENT PERIOD

This section includes responses to the one comment letter that was received after 5:00 p.m. October 19, 2021. Under CEQA, a lead agency is required to consider comments on the SEA and to prepare written responses if a comment is received within the public comment period [Public Resources Code Section 21091(d), CEQA Guidelines Section 15088]. Nonetheless, for information purposes, South Coast AQMD has elected to respond to this late comment letter.

COMMENT LETTER #6 – Western States Petroleum Association (WSPA), October 20, 2021 (p. 1 of 3)

WSPA

Patty Senecal
Senior Director, Southern California Region

October 20, 2021

Via Email

Barbara Radlein
bradlein@aqmd.gov
Program Supervisor, CEQA
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Comments on Draft Subsequent Environmental Assessment for Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations (PR 1109.1), Proposed Rule 429.1 – Startup and Shutdown Provisions at Petroleum Refineries and Related Operations (PR 429.1), Proposed Amended Rule 1304 – Exemptions (PAR 1304), Proposed Amended Rule 2005 – New Source Review for RECLAIM (PAR 2005), and Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries

Dear Ms. Radlein:

Western States Petroleum Association (WSPA) appreciates the opportunity to provide comments on the above-referenced Draft Subsequent Environmental Assessment (Draft SEA).[1] WSPA is a non-profit trade association representing companies that explore for, produce, refine, transport, and market petroleum, petroleum products, natural gas, and other energy supplies in five western states including California. WSPA has been an active participant in air quality planning issues for over 30 years. WSPA-member companies operate petroleum refineries and other facilities in the South Coast Air Basin that are within the purview of the RECLAIM Program administered by the South Coast Air Quality Management District (SCAQMD). WSPA and its individual member companies have been active participants in the development of the new and amended rules covered by the Draft SEA and have provided extensive information to the staff to support preparation of the Draft SEA. 6-1

As explained in the Draft SEA, among the intended uses of the document is to support future discretionary actions of the SCAQMD, other state and local agencies, and cities and counties that might be required to issue permits and other approvals to facilities that are subject to PR 1109.1 in order to implement projects necessary to comply with the rule.[2] The California Environmental Quality Act (CEQA) and the implementing regulations (CEQA Guidelines) strictly limit the circumstances under which subsequent environmental review is required

[1] http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2021/pr-1109-1-draft-sea.pdf?sfvrsn=6
[2] Draft SEA, p. 1.14.

COMMENT LETTER #6 – Western States Petroleum Association (WSPA), October 20, 2021 (p. 2 of 3)

October 20, 2021
Page 2

after an Environmental Impact Report, or a substitute document such as the Draft SEA, has been certified.[3] These provisions, and the case law interpreting them, stand for the proposition that once CEQA environmental review is complete, finality is favored. This presumption is overcome only if there is substantial evidence that changes in the project, changes in circumstances, or new information that could not have been known at the time the prior CEQA review was completed, show new significant impacts or a substantial increase in previously analyzed significant impacts.[4] 6-1 cont

WSPA is pleased that the Draft SEA includes a comprehensive analysis of the types and numbers of projects that likely will be required to implement PR 1109.1 and their associated environmental impacts. We offer the following recommendations for supplementing staff's already robust analysis.

These recommendations require only minor adjustments and clarifications that would not necessitate recirculation of the Draft SEA.

1. Clarify that in addition to ammonia, ammonium sulfate emissions associated with operating Selective Catalytic Reduction controls have been addressed.

The Draft SEA discusses ammonium sulfate emissions in several locations throughout the document and the cumulative air quality impact analysis identifies that the operational phase of the project will result in less than significant increases of PM10 and PM2.5 emissions. To clarify that PM10 and PM2.5 impacts associated with ammonium sulfate emissions emitted directly from equipment that is being replaced and/or retrofitted with NOx post-combustion control equipment to comply with PR 1109.1 have been addressed, we recommend the following revisions to the first paragraph on page 4.2-52: 6-2

> *In an SCR system, the ammonia or urea is injected into the flue gas stream and reacts with NOx to form elemental nitrogen (N2) and water in the cleaned exhaust gas. ~~A small~~ <u>Some</u> amount of unreacted ammonia <u>may react with SOx in the refinery fuel gas that is burned by the boiler or process heater to form ammonium sulfate that is emitted directly from the unit, or</u> ~~(ammonia slip)~~ may pass through <u>as ammonia slip</u>.*
>
> ...
>
> *The overall decrease in annual PM2.5 concentration would occur as long as 14 tons per day of NOx emissions would be reduced, even if there was an uptick in the regional concentration of PM2.5 emissions due to ammonia slip <u>and ammonium sulfate</u>.*

[3] California Public Resources Code Section 21166 (Pub. Resources Code, § 21166) and Title 14, California Code of Regulations (CEQA Guidelines), Section 15162 (14 Cal. Code Regs. § 15162).
[4] *Id.*

Western States Petroleum Association 1415 L. Street, Suite 900, Sacramento, CA 95814

COMMENT LETTER #6 – Western States Petroleum Association (WSPA), October 20, 2021 (p. 3 of 3)

October 20, 2021
Page 3

2. Clarify the application of Rule 1304 limited BACT exemption to replacement projects.

Consistent with our discussions during the rulemaking process, the PAR 1304 Draft Staff Report beginning on page 2-3, states that the limited BACT exemption applies to projects that replace equipment in different source categories as long as the federal "replacement unit" definition and guidance is used for the purposes of determining whether or not federal New Source Review applies to the project.[5] However, language included in Table 1.4-1, Item 9, of the Draft SEA states otherwise. We believe that the language in the Draft SEA reflects an earlier understanding of this issue and is now outdated and should be clarified to reflect the current understanding. 6-3

3. Clean up inconsistency between the appendix and the body of the Draft SEA related to estimates of construction GHG emissions. 6-4

The GHG construction emissions provided in the body of the Draft SEA, when totaled by facility, are not consistent with the CalEEMod runs in the Appendix.

4. Clarify emissions associated with construction truck traffic.

Please clarify that truck emissions associated with equipment delivery and removal of equipment are included in the air quality impact discussion that begins on page 4.2-8 of the Draft SEA. 6-5

Thank you for taking these suggestions into consideration as you finalize the Draft SEA. If you have any questions, please contact me at (310) 808-2144 or via e-mail at psenecal@wspa.org.

Sincerely,

Patty Senecal

Cc: Wayne Nastri, SCAQMD
Susan Nakamura, SCAQMD
Mike Krause, SCAQMD
Cathy Reheis Boyd, WSPA

RESPONSE TO COMMENT LETTER #6 – Western States Petroleum Association (WSPA), October 20, 2021

Response 6-1
South Coast AQMD staff appreciates the commenter's input and participation throughout the development of the proposed project. As noted by the comment and as explained in Chapter 1 of the SEA, if the South Coast AQMD Governing Board certifies the Final SEA and approves the proposed project, any affected facility operator who proposes to install air pollution control equipment and other components necessary to the installation of that equipment for the purpose of complying with the BARCT emission standards in the proposed project and submits South Coast AQMD permit applications, the individual project would need to undergo a CEQA review to determine if the individual project can rely on the Final SEA or if further CEQA analysis is warranted before any approvals can be granted.

Each of the individual facility's air pollution reduction projects necessary to implement the requirements of PR 1109.1 would likely require at least one permit from South Coast AQMD to construct air pollution control equipment, replace equipment, or both. Also, many of these facility-specific projects are likely to require building permits and possibly other permits from their local agencies. Since it is uncertain exactly which air pollution control technologies will be selected for each facilities air pollution reduction project, it is not feasible to identify all applicable local agency permits that may be required in the future.

South Coast AQMD staff has reviewed the comments submitted in this letter as well as the other comment letters in this appendix, and determined that none of the comments raise significant environmental issues nor require revisions to the SEA that would be considered significant new information requiring recirculation of the Draft SEA for further public comment under CEQA Guidelines Sections 15073.5 and 15088.5. Further, none of the comments indicate that the proposed project will result in a significant new environmental impact not previously disclosed in the Draft SEA. Additionally, none of comments indicate that there would be a substantial increase in the severity of a previously identified environmental impact that will not be mitigated, or that there would be any of the other circumstances requiring recirculation as described in CEQA Guidelines Sections 15073.5 and 15088.5.

Response 6-2

As recommended, the suggested edits have been incorporated into the "Regional PM2.5 Impacts from Ammonia Slip" discussion in Chapter 4, Section 4.2.2 - Potential Air Quality Impacts and Mitigation Measures of the Final SEA.

Response 6-3
The BACT exemption provided in PAR 1304 can be used for situations where a unit will be replaced with a new unit from a different source category (e.g., a boiler for a turbine). If the new unit is installed to meet a NOx BARCT limit and serves the same purpose, then the BACT exemption will not be restricted to require the new unit to be from the same source category. Table 1.4-1, Item 9 in Chapter 1 of the Final SEA has been updated to reflect this understanding.

Response 6-4

To remedy the inconsistency, the GHG emission estimates during construction as presented in Chapter 4, Tables 4.2-64a and 4.2-64b and in Appendix C of the Final SEA have been updated. The updated GHG emission estimates reflect fewer overall GHG emissions relative to the quantity originally presented in the Draft SEA but remain significant. Thus, no change to the overall conclusion for GHG emissions is necessary.

Response 6-5

The original analysis in the December 2015 Final PEA for NOx RECLAIM and the analysis in this Final SEA, applied the same modeling parameters as the December 2015 Final PEA for NOx RECLAIM, and take into account a variety of overlapping truck trips that may occur on a peak day for each type of construction scenario, and these truck trips include deliveries of supplies, equipment, chemicals and hauling away various materials such as construction waste and spent catalyst during construction. See Appendix B, section "3.0 Construction Detail" in each CalEEMod run which includes two hauling trips per day in each of the phases listed in the "Trips and VMT" subsection.

PROPOSED RULE 1109.1
EMISSIONS OF OXIDES OF NITROGEN FROM PETROLEUM REFINERIES AND RELATED OPERATIONS

PROPOSED RESCINDED RULE 1109
EMISSIONS OF OXIDES OF NITROGEN FROM BOILERS AND PROCESS HEATERS IN PETROLEUM REFINERIES

PROPOSED RULE 429.1
STARTUP AND SHUTDOWN PROVISIONS AT PETROLEUM REFINERIES AND RELATED OPERATIONS

PROPOSED AMENDED RULE 1304
EXEMPTIONS

PROPOSED AMENDED RULE 2005
NEW SOURCE REVIEW FOR RECLAIM

ATTACHMENT V

South Coast AQMD

BOARD MEETING
NOVEMBER 5, 2021

Background

- Proposed Rule 1109.1 (PR 1109.1) applies to five major petroleum refineries[1], three small refineries, and four facilities with related operations
- Establishes NOx BARCT limits for nearly 300 pieces of combustion equipment
- Partially implements CMB-05 in the 2016 AQMP which
  - Seeks an additional 5 tons per day of NOx reductions from NOx RECLAIM
  - Commits to transitioning NOx RECLAIM facilities to command-and-control
- PR 1109.1 needed to meet AB 617 requirements to establish BARCT for all industrial sources

[1] Five major petroleum refineries representing nine individual facilities

Overview of Rulemakings Related to PR 1109.1

Proposed Rule 1109.1

Establishes NOx and CO concentration limits for combustion equipment at petroleum refineries and facilities with operations related to petroleum refineries

Other Rulemakings to Support PR 1109.1

Proposed Rule 429.1	Provides exemptions from PR 1109.1 NOx concentration limits when units are starting up and shutting down, and certain maintenance activities
Proposed Amended Rules 1304 and 2005	Provides a narrow NSR exemption for BACT when meeting PR 1109.1 limits provided increases are below federal New Source Review thresholds
Proposed Rescinded Rule 1109	Existing rule for large refinery boilers and heaters that is proposed to be rescinded

PR 1109.1 and Supporting Rules were Developed Through an Extensive Public Process

25

Working Group Meetings

Discussed details of PR 1109.1 and proposed concepts

3

Public Meetings

Two community meetings, including an AB 617 meeting, and one Public Workshop

100+

Stakeholder Meetings

Meetings with environmental and community groups, individual facilities, WSPA, and agencies

5

Committee Briefings

Began briefing the Stationary Source Committee September 2020

Core Requirements

- Operators must meet NOx limits in Table 1
- If the conditional requirements can be met, operators can meet Table 2 “conditional NOx limits” in lieu of Table 1 limits
- Table 2 Conditional NOx limits developed to:
  - Ensure Table 1 NOx limits are cost-effective
  - Acknowledge units with a cost-effectiveness >>$50,000 per ton of NOx reduced
  - Require that new Selective Catalytic Reduction (SCR) installations meet Table 1 limits
  - Provide safeguards to maximize cost-effective emission reductions

TABLE 1: NOx AND CO CONCENTRATION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers <40 MMBtu/hour	Pursuant to subparagraphs (d)(2)(A) and (d)(2)(B)	400	3	24-hour
Boilers ≥40 MMBtu/hour	5	400	3	24-hour
FCCU	2	500	3	365-day
	5			7-day
Flares	20	400	3	2-hour
Gas Turbines fueled with Natural Gas	2	130	15	24-hour
Gas Turbines fueled with Gaseous Fuel other than Natural Gas	3	130	15	24-hour
Petroleum Coke Calciner	5	2,000	3	365-day
	10			7-day
Process Heaters <40 MMBtu/hour	Pursuant to subparagraphs (d)(2)(A) and (d)(2)(C)	400	3	24-hour
Process Heaters ≥40 MMBtu/hou	5	400	3	24-hour
SMR Heaters				
SMR Heaters with Turbine				
SRU/TG Incinerat				
Sulfuric Acid Furn				
Vapor Incinerato				

TABLE 2: CONDITIONAL NOx AND CO CONCENTRATION LIMITS

Unit	NOx (ppmv)	CO (ppmv)	O_2 Correction (%)	Rolling Averaging Time[1]
Boilers >110 MMBtu/hour	7.5	400	3	24-hour
FCCUs	8	500	3	365-day
	16			7-day
Gas Turbines fueled with Natural Gas	2.5	130	15	24-hour
Process Heaters ≥40 – ≤110 MMBtu/hour	18	400	3	24-hour
Process Heaters >110 MMBtu/hour	22	400	3	24-hour
SMR Heaters	7.5	400	3	24-hour
Vapor Incinerators	40	400	3	24-hour

All Equipment Categories Have an Average Cost-Effectiveness Below $50,000 per ton of NOx Reduced

However, to Achieve the Low NOx Limits the Average Cost is ~$20 Million per Project

The B-Plan and B-Cap were included to address the high cost of PR 1109.1

B-Plan

- B-Plan is a BARCT equivalent concentration plan
- Operators select alternative NOx concentration limits that are equivalent to BARCT in the aggregate

B-Cap

- B-Cap is a BARCT equivalent mass cap
- Emission reductions from shutdowns can be used to meet mass emission cap
- Operators must have "not to exceed" alternative NOx concentration limits

The B-Plan and B-Cap Provide Compliance Flexibility With the Same or Greater Emission Reductions

B-Plan and B-Cap have emission targets based on reductions that would be achieved if each unit met the Table 1 and 2 NOx limits

B-Cap requires an additional 10 percent environmental benefit requiring additional reductions

Need for Alternative Implementation Approach

150+ Projects

- ~90 new or upgraded SCR projects
- ~75 Low-NOx Burner projects

Complexity of Projects

- Each project is customized for the unit
- Must incorporate within existing facility structure

Limited Resources

Competing for same pool of skilled labor, equipment manufacturers, source testing companies, etc.

Continuous Fuel Supply

Allowing projects to be implemented within existing maintenance schedule eliminates disruption in fuel supply

I-Plan

- I-Plan is a phased implementation schedule
- Five I-Plan options
- Targets are the percent of the required reductions

I-Plan Options	Provision	Phase I	Phase II	Phase III
Option 1 for B-Plan or Table 1 or 2	Targets	80%	100%	
	Submit Permit Application	Jan 1, 2023	Jan 1, 2031	
Option 2 B-Plan[1]	Targets	65%	100%	
	Submit Permit Application	July 1, 2024	Jan 1, 2030	
Option 3 B-Plan or B-Cap[1,2]	Targets	40%	100%	
	Submit Permit Application	July 1, 2025	July 1, 2029	
Option 4 B-Cap Only[2]	Targets	50%	80%	100%
	Submit Permit Application	N/A	Jan 1, 2025	Jan 1, 2028
Option 5 for B-Plan or Table 1 or 2	Targets	50%	70%	100%
	Submit Permit Application	Jan 1, 2023	Jan 1, 2025	July 1, 2028

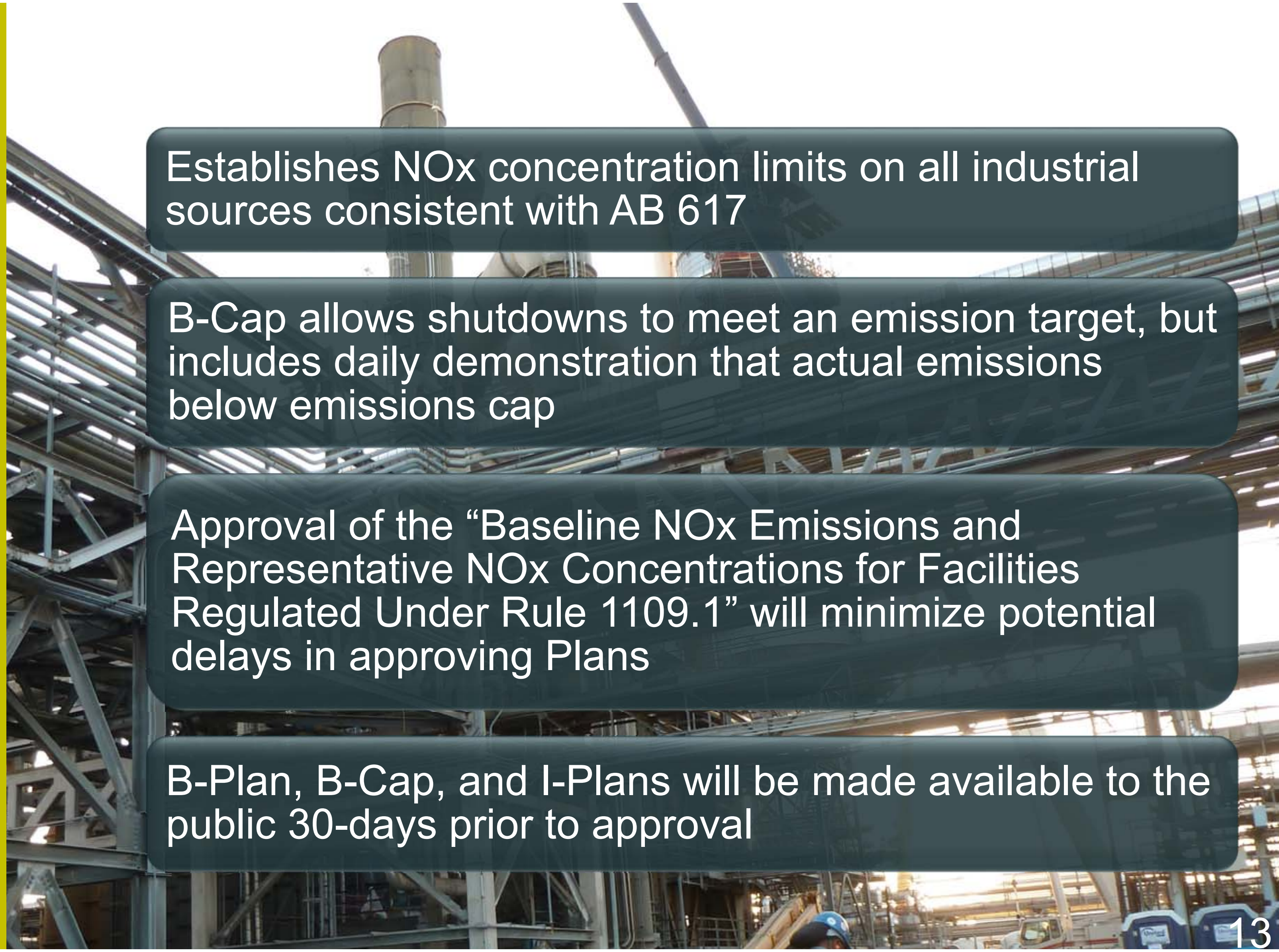
[1] Available for facilities with boilers and heaters ≥ 40 MMBtu meeting 0.02 lbs/MMBtu.

[2] 10 percent environmental benefit is incorporated in overall reductions.

Although Implementation of Some I-Plans will Extend to 2035…

Targets in the I-Plans are Designed to Achieve ~75% of the Required Reductions by 2027 and ~ 90% of the Required Reductions by 2031[1]

[1] Emission reductions based on 30 months after permit submittal date



Other Key Features of the I-Plan, B-Plan, and B-Cap

Establishes NOx concentration limits on all industrial sources consistent with AB 617

B-Cap allows shutdowns to meet an emission target, but includes daily demonstration that actual emissions below emissions cap

Approval of the “Baseline NOx Emissions and Representative NOx Concentrations for Facilities Regulated Under Rule 1109.1” will minimize potential delays in approving Plans

B-Plan, B-Cap, and I-Plans will be made available to the public 30-days prior to approval

PR 1109.1 NOx Reductions

AB 617
Expedited BARCT
Maximum degree of reductions achievable by Dec. 31, 2023

3.7 to 3.8 tpd

+

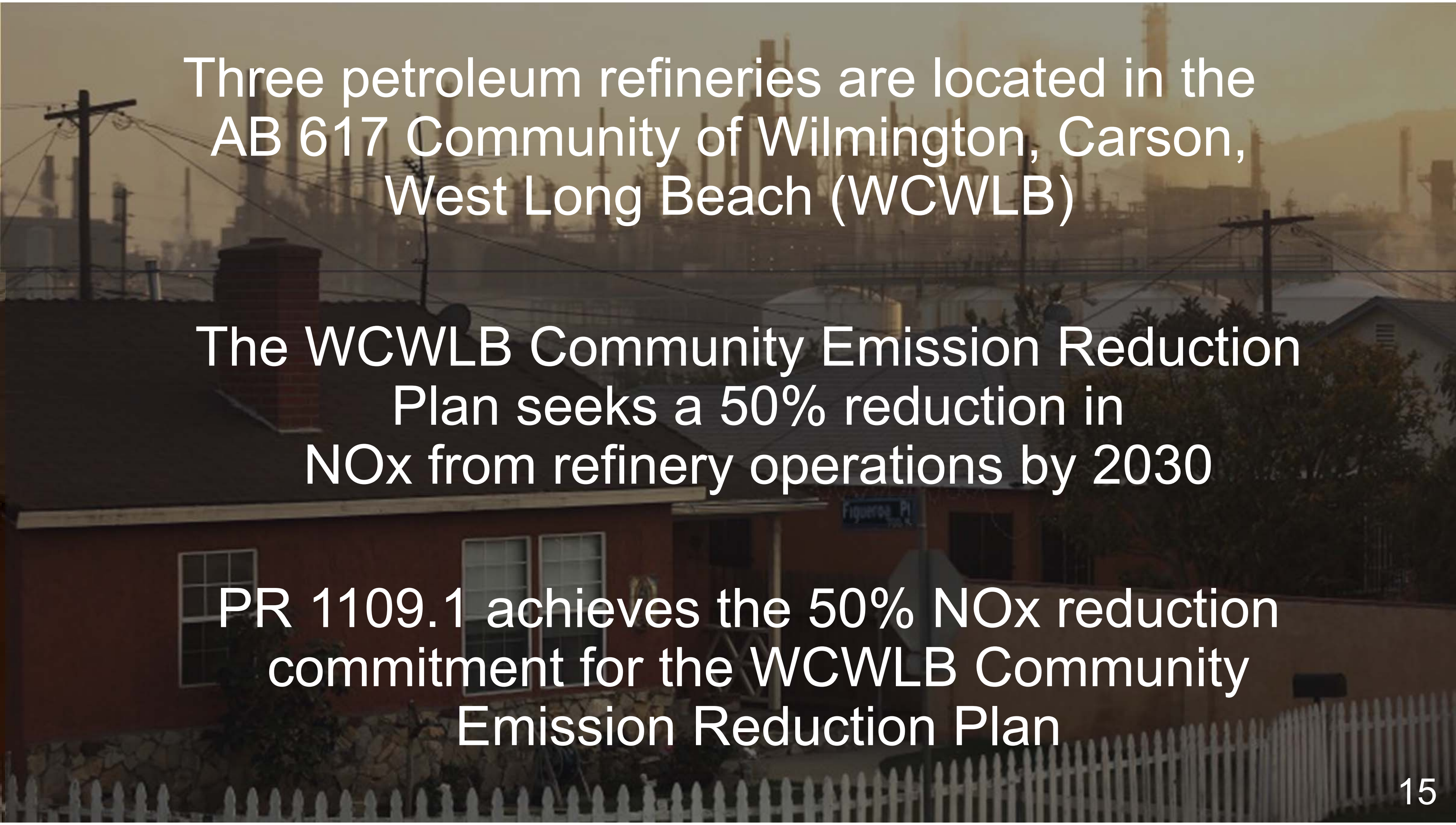
AB 617 "PLUS"
Maximum degree of reductions achievable after Dec. 31, 2023

4.0 to 4.1 tpd

=

Total PR 1109.1 Reductions

7.7 to 7.9 tpd


Three petroleum refineries are located in the AB 617 Community of Wilmington, Carson, West Long Beach (WCWLB)
The WCWLB Community Emission Reduction Plan seeks a 50% reduction in NOx from refinery operations by 2030
PR 1109.1 achieves the 50% NOx reduction commitment for the WCWLB Community Emission Reduction Plan

Socioeconomic Impact Assessment Estimated the Total Cost to Implement PR 1109.1 is $2.3 Billion with an Average Annual Cost of $133 Million per Year

Socioeconomic Impact Assessment Also Found Positive Impacts

Projected annual average increase of 213 jobs per year

Less than one cent per gallon projected increase in gasoline prices

$2.6 Billion monetized health benefits

370 premature deaths avoided*

6,200 asthma attacks avoided*

21,400 work loss days avoided*

* Over the time period from 2023 to 2037

Key Issues Resolved During the Rulemaking

- RTC — Achieve NOx limits without use of RECLAIM Trading Credits
- PM SOx — Include a narrow BACT exemption for co-pollutants when installing SCR systems to achieve PR 1109.1 NOx limits
- Includes an alternative implementation approach to address complexity and number of projects
- $ — Incorporated incremental cost-effectiveness when establishing BARCT limit
- Include flexibility to address high compliance cost

Key Remaining Issue: Some Questioned if PR 1109.1 Meets AB 617 Expedited BARCT

- PR 1109.1 meets AB 617 expedited BARCT and will achieve 3.7 to 3.8 tons per day of NOx by 2023
  - Early action projects anticipated to be completed by 2023
  - Expedited schedule to meet Table 2 limits
  - Largest refinery in the region expected to reduce 50% of required reductions by January 1, 2024
- “AB 617 Plus” approach provides additional BARCT reductions that will result in an additional 4.0 to 4.1 tons per day of NOx post 2023
  - Provides greatest health benefits for the communities
  - Meets the goals of AB 617 Community Emission Reduction Plan of 50% NOx reduction by 2030
  - Results in substantial progress towards achieving attainment of the federal ozone standards

Conclusions

Substantial Public Process to Resolve Wide Variety of Key Issues

Meets AB 617 and Community Commitment for 50% NOx Reduction

Resources in place to process ~300 Permit Applications, With Addition of at Least One Engineer

Compliance Plans Address High Costs and Complexity of Projects

Will Achieve Substantial NOx Emission Reductions of 7.7 to 7.9 tons per day

Recommendation

- Adopt Resolution:
  - Certifying the Final Subsequent Environmental Assessment for:
    - *Proposed Rule 1109.1*
    - *Proposed Rule 429.1*
    - *Proposed Amended Rule 1304*
    - *Proposed Amended Rule 2005*
    - *Proposed Rescinded Rule 1109*
  - Adopting Rules 1109.1 and 429.1, Amending Rules 1304 and 2005, and Rescinding Rule 1109
  - Approving “Baseline NOx Emissions and Representative NOx Concentrations for Facilities Regulated Under Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations”