BOARD MEETING DATE: October 2, 2020 AGENDA NO. 28

PROPOSAL: Certify Final Environmental Assessment and Adopt Rule 1179.1 – Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities

SYNOPSIS: Proposed Rule 1179.1 (PR 1179.1) establishes NOx, VOC, and CO emission limits for boilers, process heaters, engines, and turbines at Publicly Owned Treatment Works facilities. PR 1179.1 will consolidate requirements from existing source-specific rules and incorporates new requirements for turbines, which are currently exempt from existing source-specific rules. PR 1179.1 also includes provisions for starting up and shutting down equipment, and monitoring, reporting and recordkeeping.

COMMITTEE: Stationary Source, August 21, 2020, Reviewed

RECOMMENDED ACTIONS:
Adopt the attached Resolution:
1. Certifying the Final Environmental Assessment for Proposed Rule 1179.1 – Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities; and
2. Adopting Rule 1179.1 – Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities.

Wayne Nastri
Executive Officer

PMF:SN:MM:KO:MG

Background
In 2018 during the rulemaking for Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional and Commercial Boilers, Steam Generators, and Process Heaters and Rule 1146.1 – Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, representatives from the Southern California Association of Publicly Owned Treatment Works highlighted challenges that are unique to treating municipal wastewater such as use of digester gas instead of natural gas in combustion equipment, financial constraints due to public funding and that they provide an essential public service. In response, staff recommended that provisions for combustion equipment at publicly owned treatment works (POTWs) and landfills be separated from existing source-specific rules and to

consolidate provisions for combustion equipment at POTWs and landfills in separate rules. Proposed Rule 1179.1 – Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities, (PR 1179.1) consolidates provisions for combustion equipment at POTWs from existing rules that establish emission limits for units using digester gas as well as establishing emission limits for units at POTWs that are currently not regulated under existing source-specific rules.

Public Process

The development of PR 1179.1 was conducted through a public process. A working group was formed that included POTW representatives, equipment vendors, other agencies, community and environmental groups and other interested parties. Five working group meetings were held to discuss rule concepts. A public workshop was held on July 22, 2020 to present the proposed rule to the general public and to stakeholders. Staff also conducted multiple site visits and has met with individual facility operators to better understand issues unique to their operations and work through key issues.

Proposal

Through the PR 1179.1 rulemaking process, a detailed BARCT analysis was performed for boilers and turbines recognizing the unique challenges of burning digester gas. PR 1179.1 incorporates the emission limits and other provisions related to the use of digester gas under Rules 1146 and 1146.1 for boilers and process heaters and Rule 1110.2 - Emissions from Gaseous- and Liquid-Fueled Engines, for engines. PR 1179.1 establishes NOx and CO emission limits for boilers, process heaters and engines burning digester gas or those units capable of burning digester and natural gas and VOC emission limits for engines. Emission limits for these units are the same as those in Rules 1146 and 1146.1 for boilers and heaters and Rule 1110.2 for engines. PR 1179.1 also includes NOx and CO emission limits for small boilers and process heaters at or below 2 MMBtu/hour using digester gas, which are currently unregulated.

Since turbines at POTWs are currently exempt from Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines, PR 1179.1 establishes NOx and CO emission limits for turbines burning digester gas, natural gas and units capable of burner digester and natural gas. Based on the BARCT analysis, turbines greater than or equal to 0.3 MW are required to meet a NOx emission limit of 18.8 ppm. PR 1179.1 also establishes NOx and CO emission limits for digester gas and dual fuel turbines that are less than 0.3 MW. Other provisions in PR 1179.1 include equipment-specific averaging times, and startup and shutdown requirements, and monitoring, reporting and recordkeeping requirements.

Emission Reductions

NOx emissions in 2019 were 0.20 tons per day. Implementation of PR 1179.1 would result in the reduction of NOx emissions from this baseline by 0.05 tons per day. Reductions would be achieved with a change to the control method process on three turbines at one facility. PR 1179.1 and the NOx emission reductions will be submitted into the State Implementation Plan.

Key Issues

Throughout the rulemaking process, staff has worked with stakeholders to resolve issues regarding the applicability, emission limits for dual fuel units, proposed emission limits, startup and shutdown provisions and the implementation schedule. Staff is not aware of any remaining key issues.

California Environmental Quality Act

PR 1179.1 is 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 15070, the South Coast AQMD has prepared a Final Environmental Assessment (EA) for PR 1179.1, which is a substitute CEQA document, prepared in lieu of a Negative Declaration. The environmental analysis in the Final EA concluded that PR 1179.1 would not generate any significant adverse environmental impacts. The Final EA is included as Attachment H.

Socioeconomic Analysis

Proposed Rule 1179.1 affects 30 POTW facilities with a total of 86 digester gas fueled boilers, turbines and engines. Only one facility is expected to incur increased annual compliance costs as a result of increased water injection to achieve the NOx emission limits for three turbines. Most permitted equipment at Title V and non-Title V facilities will require a one-time permit modification fee.

The cost for implementing PR 1179.1 is approximately $453,000 per year. The cost-effectiveness is estimated at $50,000 per ton of NOx reduced.

Resource Impacts

Existing staff resources are adequate to implement the proposed amendments.

Attachments

A. Summary of Proposal
B. Key Issues and Responses
C. Rule Development Process
D. Key Contacts List
E. Resolution
F. Proposed Rule 1179.1
G. Final Staff Report
H. Final Environmental Assessment
I. Board Meeting Presentation

ATTACHMENT A

SUMMARY OF PROPOSAL

Proposed Rule 1179.1 – Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities
Applicability Applies to: • Digester gas and dual fuel boilers and process heaters over 400,000 Btu/hr • Digester gas and dual fuel turbines less than 0.3 MW • Turbines greater than or equal to 0.3 MW; and • Digester gas and dual fuel engines greater than 50 rated brake horsepower. *Emission limits* • Boiler and process heater NOx and CO limits (3% oxygen, averaged over 15 minutes) o Boilers and process heaters > 2 MMBtu/hr using digester gas is 15 ppm and natural gas units is 9 ppm with CO limits regardless of the fuel at 400 ppm (Same as Rules 1146 and 1146.1) o Boilers and heaters ≤ 2 MMBtu/hr using digester or natural gas is 30 ppm o Firing less than 90% digester gas and less than 100% natural gas – subject to a weighted limit • Turbine limits (15% oxygen, averaged over 1 hour) o Turbines ≥ 0.3 MW firing at least 60% digester gas – 18.8 ppm o Turbines ≥ 0.3 MW firing 100% natural gas, 2 ppm for combined cycle turbines and 2.5 ppm for simple cycle turbines o Firing less than 60% digester gas and less than 100% natural gas – subject to a weighted limit o Digester gas and dual fuel turbines < 0.3 MW is 9 ppm • Engine limits (15 percent oxygen, averaged over 15 minutes) o Engines using digester gas > 50 bhp is 11 ppm NOx, 250 ppm CO, and 30 ppm VOC (same as Rule 1110.2) *Averaging times for units with CEMS* • Fixed interval of 1 hour for boilers • Rolling period of 1 hour for turbines • Fixed interval of 1 hour for engines, with options for 24 and 48 hours under certain specific conditions

Startup and Shutdown

- Boilers: Until boiler and/or control equipment is properly operating and cannot exceed 6 hours
- Turbines: Until control equipment is properly operating and cannot exceed 2 hours for turbines with SCR and 3 hours for turbines without SCR
- Engines: Until engine and control equipment are properly operating and cannot exceed 30 minutes

Source Testing and Continuous Emissions Monitoring Systems (CEMS)

- Source testing frequency, test methods, and protocol submittals are consistent with other source-specific rules
- CEMS requirements for applicability and requirements consistent with other source-specific rules

Other Provisions

- Inspection and Monitoring Plans consistent with current Rule 1110.2 requirements
- Diagnostic emission checks for boilers and engines consistent with current source-specific rules

Recordkeeping

- Requirements for types of records and record retention time for all units
  - Startup and shutdown records for boilers
  - Operating logs for turbines and turbine control equipment
  - Operating logs and breakdown reporting for engines
  - Records of tuning and servicing and hours of operation subsequent to tuning and servicing and prior to emissions testing

Compliance schedule

- Establishes the schedule for permit revision applications to reflect PR 1179.1
  - Title V facilities can submit equipment permit applications on the same schedule as their Title V renewal application
  - Boilers > 2 MMBtu/hr: by January 1, 2023
  - Boilers ≤ 2 MMBtu/hr: by July 1, 2023
  - Engines and I&M plans: by January 1, 2024
  - Turbines: by July 1, 2024

- *Exemptions*
  - Applicable to certain low-use units, boilers, turbines ≤ 0.3 MW, and engines permitted to fire exclusively natural gas, smaller equipment without concentration limits, and units under variances

ATTACHMENT B

KEY ISSUES AND RESPONSES

Proposed Rule 1179.1 – Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities

Throughout the rulemaking process, staff worked closely with stakeholders to address their comments and have resolved all key issues. Staff is not aware of any remaining key issues.

ATTACHMENT C

RULE DEVELOPMENT PROCESS

Proposed Rule 1179.1 – Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities

Initial Rule Development:
February 2019

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Five Working Group Meetings: May 2, 2019, August 13, 2019, November 6, 2019, February 12, 2020, and June 4, 2020

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75-Day Notice of Public Workshop: July 7, 2020
Public Workshop: July 22, 2020

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Draft Environmental Assessment: August 12, 2020

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Stationary Source Committee Meeting: August 21, 2020

↓

30-Day Notice of Public Hearing: September 2, 2019

↓

Set Public Hearing: September 4, 2019

↓

Public Hearing: October 2, 2020

Twenty-two (22) months spent in rule development.

Five (5) Working Group Meetings

One (1) Public Workshop

One (1) Stationary Source Committee Meeting

ATTACHMENT D

KEY CONTACTS LIST

ALZETA Corporation
Banning City Wastewater Treatment Plant
Bryan Power Generation
California Boiler
Capstone Turbine
Corona City Department of Water & Power
Eastern Municipal Water District
Faber Burner Company
FERCo
GE
Generon
Inland Empire Utilities Agency
Irvine Ranch Water District
LA City Sanitation Bureau
LA City Terminal Island Treatment Plant
LA County Sanitation District
Las Virgenes Municipal Water District
Nationwide Boiler
Orange County Sanitation District
Parker Boiler
Pioneer Air Systems
Puretec
R.F. MacDonald Company
Redlands City Wastewater Treatment Plant
Rentech Boilers
Rialto City
Riverside City Water Quality Control
San Bernardino Municipal Water Department
San Clemente City
Santa Margarita Water District
Siemens
Solar Turbines
South Orange County Wastewater Authority
Southern California Association of Publicly Owned Treatment Works
Umicore Catalyst USA, LLC
Unison Solutions
Valley Sanitation District
Western Municipal Water District
Western Riverside County Regional Wastewater Authority Treatment Plant
Willexa Energy
Yucaipa Valley Water District

ATTACHMENT E

RESOLUTION NO. 20-____

A Resolution of the Governing Board of the South Coast Air Quality Management District (South Coast AQMD) certifying the Final Environmental Assessment (EA) for Proposed Rule 1179.1 – Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities.

A Resolution of the South Coast AQMD Governing Board adopting Rule 1179.1 – Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities.

WHEREAS, the South Coast AQMD Governing Board finds and determines with certainty that Proposed Rule 1179.1 is 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 Proposed Rule 1179.1 pursuant to such program (South Coast AQMD Rule 110); and

WHEREAS, the South Coast AQMD Governing Board has determined that the requirements for a Negative Declaration have been triggered pursuant to its Certified Regulatory Program and CEQA Guidelines Section 15070, and that an Environmental Assessment (EA), a substitute document allowed pursuant to CEQA Guidelines Section 15252 and South Coast AQMD's Certified Regulatory Program, is appropriate; and

WHEREAS, the South Coast AQMD prepared a Draft EA pursuant to its Certified Regulatory Program and CEQA Guidelines Section 15070 setting forth the potential environmental consequences of Proposed Rule 1179.1 and determined that the proposed project would not have the potential to generate significant adverse environmental impacts; and

WHEREAS, a Draft EA was prepared and circulated for a 30-day public review and comment period from August 12, 2020 to September 11, 2020, and one comment letter was received; and

WHEREAS, the Draft EA has been revised to include the comment letter received on the Draft EA and the response, so that it is now a Final EA; and

WHEREAS, it is necessary that the South Coast AQMD Governing Board review the Final EA 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 Proposed Rule 1179.1, including the responses to the comment letter received relative to the Draft EA; and

WHEREAS, pursuant to CEQA Guidelines Section 15252 (a)(2)(B), since no significant adverse impacts were identified, no alternatives or 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 not been prepared; and

WHEREAS, Findings pursuant to Public Resources Code Section 21081.6 and CEQA Guidelines Section 15091 and Statement of Overriding Considerations pursuant to CEQA Guidelines Section 15093 were not prepared because the analysis shows that Proposed Rule 1179.1 would not have a significant adverse effect on the environment, and thus, are not required; and

WHEREAS, the South Coast AQMD Governing Board voting to adopt Proposed Rule 1179.1 has reviewed and considered the information contained in the Final EA, including the responses to the comment letter, and all other supporting documentation, prior to its certification, and has determined that the Final EA, including the responses to the comment letter received, has been completed in compliance with CEQA; and

WHEREAS, Proposed Rule 1179.1 and supporting documentation, including but not limited to, the Final EA and Final Staff Report, 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 EA reflects the independent judgement of the South Coast AQMD; and

WHEREAS, the South Coast AQMD Governing Board finds and determines that all changes made in the Final EA after the public notice of availability of the Draft EA 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 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 EA, 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 (codified as Section 30.5(4)(D)(i) of the Administrative Code), that the modifications to the title of Proposed Rule 1179.1, Table 1, paragraph (e)(11), and subparagraphs (d)(4)(A), (d)(5)(B), and (d)(5)(C) since the notice of public hearing was published are clarifications and are not so substantial as to significantly affect the meaning of the proposed rule within the meaning of Health and Safety Code Section 40726 because: (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 consideration of the range of CEQA alternatives is not applicable because Proposed Rule 1179.1 does not cause significant impacts and therefore, alternatives are not required; and

WHEREAS, the South Coast AQMD Governing Board has determined that the Socioeconomic Impact Assessment of Proposed Rule 1179.1 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 Socioeconomic Impact Assessment is consistent with the provisions of Health and Safety Code Sections 40440.8, 40728.5, and 40920.6; and

WHEREAS, the South Coast AQMD Governing Board has determined that Proposed Rule 1179.1 will result in increased costs to the affected industries, yet are considered to be reasonable, with a total annualized cost as specified in the Socioeconomic Impact Assessment; and

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

WHEREAS, the South Coast AQMD staff conducted a Public Workshop regarding Proposed Rule 1179.1 on July 22, 2020; and

WHEREAS, Proposed Rule 1179.1 will be submitted for inclusion into the State Implementation Plan; 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 a need exists to adopt Proposed Rule 1179.1 to address specific equipment located at publicly owned treatment works facilities that were not addressed in recently amended rules and that are currently not regulated; 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, 40702, 40725 through 40728, 41508, and 41700 of the Health and Safety Code; and

WHEREAS, the South Coast AQMD Governing Board finds that there is an ozone problem that Proposed Rule 1179.1 will alleviate and will promote the attainment or maintenance of state or federal ambient air quality standards; and

WHEREAS, the South Coast AQMD Governing Board has determined that Proposed Rule 1179.1 is written or displayed so that its meaning can be easily understood by the persons directly affected by it; and

WHEREAS, the South Coast AQMD Governing Board has determined that Proposed Rule 1179.1 is 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 1179.1 does not impose the same requirements as any existing state or federal regulations, and the proposed rule is necessary and proper to execute the powers and duties granted to, and imposed upon, South Coast AQMD; and

WHEREAS, the South Coast AQMD Governing Board, in adopting Rule 1179.1, references the following statutes which the South Coast AQMD hereby implements, interprets, or makes specific: Assembly Bill 617, Health and Safety Code Sections 39002, 40001, 40702, 40440(a), 40440(b), 40406, and 40725 through 40728.5; 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 the South Coast AQMD's comparative analysis of Proposed Rule 1179.1 in included in the Final Staff Report; and

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

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

WHEREAS, the South Coast AQMD specifies the Planning and Rules Manager of Rule 1179.1 as the custodian of the documents or other materials which constitute the record of proceedings upon which the adoption of the proposed rule 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 EA for Proposed Rule 1179.1 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 EA, including the responses to the comment letter, was completed in compliance with CEQA and the South Coast AQMD's Certified Regulatory Program, 2) finds that the Final EA 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 1179.1, and 3) certifies the Final EA; and

BE IT FURTHER RESOLVED, that because no significant adverse environmental impacts were identified as a result of adopting Rule 1179.1, Findings, a Statement of Overriding Considerations, and a Mitigation, Monitoring, and Reporting Plan are not required and were not prepared; and

BE IT FURTHER RESOLVED, that the South Coast AQMD Governing Board does hereby adopt, pursuant to the authority granted by law, Proposed Rule 1179.1 as set forth in the attached, and incorporated herein by reference; and

BE IT FURTHER RESOLVED, that the South Coast AQMD Governing Board also finds pursuant to Health and Safety Code Section 40920.6, that PAR 1179.1 is adopted because the other analyzed potential control options are not viable.

BE IT FURTHER RESOLVED, that the South Coast AQMD Governing Board requests that Proposed Rule 1179.1 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 1179.1 and supporting documentation to the California Air Resources Board for approval and subsequently submittal to the U.S. Environmental Protection Agency for inclusion into the State Implementation Plan.

DATE: ________________ ________________________________

CLERK OF THE BOARDS

ATTACHMENT F

(PR 1179.1 October 2, 2020)

PROPOSED RULE 1179.1 ~~NOX~~ EMISSION REDUCTIONS FROM COMBUSTION EQUIPMENT AT PUBLICLY OWNED TREATMENT WORKS FACILITIES

(a) Purpose

The purpose of this rule is to reduce emissions of Oxides of Nitrogen (NO_x) and Carbon Monoxide (CO) from boilers and turbines, and emissions of NOx, CO, and Volatile Organic Compounds (VOCs) from engines, located at publicly owned treatment works (POTW) facilities.

(b) Applicability

This rule applies to the following equipment located at a POTW facility:

(1) Digester gas and dual fuel boilers and process heaters over 400,000 Btu/hr;

(2) Digester gas and dual fuel turbines less than 0.3 MW;

(3) Turbines greater than or equal to 0.3 MW; and

(4) Digester gas and dual fuel engines greater than 50 rated brake horsepower.

(c) Definitions

(1) ANNUAL HEAT INPUT is the total heat input to a unit during a calendar year.

(2) BOILER is any combustion equipment fired with a liquid or gaseous fuel and used to produce steam or to heat water, and that is not used exclusively to produce electricity for sale. Boiler does not include any open heated tank, adsorption chiller unit, or waste heat recovery boiler that is used to recover sensible heat from the exhaust of a combustion turbine or any unfired waste heat recovery boiler that is used to recover sensible heat from the exhaust of any combustion equipment.

(3) BREAKDOWN is a physical or mechanical failure or malfunction of an engine, air pollution control equipment, or related operating equipment that is not the result of operator error, neglect, improper operation or improper maintenance procedures, which leads to excess emissions beyond rule related emission limits or equipment permit conditions.

(4) BTU is British thermal unit(s).

(5) COMBINED CYCLE TURBINE is a turbine that recovers heat from the gas turbine exhaust.

(6) CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) is the total combined equipment and systems, including the sampling interface, analyzers, and data acquisition and handling system, required to continuously determine air contaminants and diluent gas concentrations and/or mass emission rate of a source effluent (as applicable).

(7) DIGESTER GAS is gas that is produced by anaerobic decomposition of organic material.

(8) DIGESTER GAS UNIT is any combustion equipment subject to this rule permitted to fire digester gas exclusively.

(9) DUAL FUEL UNIT is any combustion equipment subject to this rule permitted to fire digester gas and another fuel.

(10) ENGINE is any internal combustion equipment that is spark- or compression ignited and burns liquid and/or gaseous fuel to create heat that move pistons to do work.

(11) LEAN-BURN ENGINE is an engine that operates with high levels of excess air and an exhaust oxygen concentration of greater than 4 percent.

(12) NATURAL GAS is 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.

(13) OXIDES OF NITROGEN (NOx) EMISSIONS is the sum of nitric oxides and nitrogen dioxides emitted, collectively expressed as nitrogen dioxide emissions.

(14) POST-COMBUSTION CONTROL is any air pollution control equipment which eliminates, reduces, or controls the issuance of air contaminants after combustion.

(15) PROCESS HEATER is any combustion equipment fired with liquid and/or gaseous fuel and which transfers heat from combustion gases to water or process streams. Process Heater does not include any kiln or oven 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.

(16) PUBLICLY OWNED TREATMENT WORKS FACILITY OR POTW FACILITY is a wastewater treatment or reclamation plant owned or operated by

a public entity, including all operations within the boundaries of the wastewater and sludge treatment plant.

(17) RATED BRAKE HORSEPOWER (bhp) is the rating specified by the manufacturer, without regard to any derating, and listed on the engine nameplate.

(18) RATING OF A TURBINE is the continuous MW (megawatt) rating or mechanical equivalent by a manufacturer for a turbine without including the increase in the turbine shaft output and/or the decrease in turbine fuel consumption by the addition of energy recovered from exhaust heat.

(19) RICH-BURN ENGINE is an engine designed to operate near stoichiometric conditions.

(20) SELECTIVE CATALYTIC REDUCTION (SCR) is a post-combustion control that reduces NOx with catalyst and a reducing agent.

(21) SHUTDOWN is the time period that begins when an operator reduces load and which ends in a period of zero fuel flow.

(22) SIMPLE CYCLE TURBINE is a turbine that does not recover heat from the combustion turbine exhaust gases to heat water or generate steam.

(23) STARTUP is the time period that begins when a unit combusts fuel after a period of zero fuel flow and which ends when the unit reaches stable operating conditions.

(24) THERM is 100,000 Btu.

(25) TUNING is adjusting, optimizing, rebalancing, or other similar operations to a unit or an associated control device. Tuning does not include normal operations to meet load fluctuations.

(26) TURBINE is any internal combustion equipment that burns liquid and/or gaseous fuel to create hot gas that expands to move a rotor assembly, with vanes or blades, to do work.

(27) UNIT is a boiler, turbine, or engine subject to this rule.

(d) Emission Limits

(1) On and after the compliance date specified in Table 1, an owner or operator shall not operate a unit in a manner that discharges NOx, CO, or VOC into the atmosphere in excess of the limits specified in Table 1, excluding start-up and shutdown periods as specified pursuant to paragraph (d)(5). Compliance with the emission limits in Table 1 shall be demonstrated with all applicable compliance tests as required by this rule.

TABLE 1
CONCENTRATION LIMITS

DIGESTER GAS AND DUAL FUEL BOILERS AND PROCESS HEATERS

EQUIPMENT CATEGORY	NOx (ppm)[1]	CO (ppm)[1]	COMPLIANCE DATE
Rated heat input capacity > 2 MMBtu/hr and firing 90% digester gas or more[2]	15	400	On or before [*Date of Adoption*]
Rated heat input capacity > 2 MMBtu/hr and firing 100% natural gas	9		On or before [*Date of Adoption*]
Rated heat input capacity ≤ 2 MMBtu/hr	30		On or before [*Date of Adoption*]

TURBINES

EQUIPMENT CATEGORY	NOx (ppm)[3]	CO (ppm)[3]	COMPLIANCE DATE
Rating ≥ 0.3 MW and firing 60% digester gas[4] or more	18.8	130	On or before [*Date of Adoption*]
Simple cycle with rating ≥ 0.3 MW and firing 100% natural gas	2.5		On or before [*Date of Adoption*]
Combined cycle with rating ≥ 0.3 MW and firing 100% natural gas	2		On or before [*Date of Adoption*]
Digester gas or dual fuel with r~~R~~ating < 0.3 MW	9		On or before [*Date of Adoption*]

DIGESTER GAS AND DUAL FUEL ENGINES

EQUIPMENT CATEGORY	NOx (ppm)[5]	CO (ppm)[5]	VOC (ppm)[6]	COMPLIANCE DATE
Engines > 50 bhp	11	250	30	On or before [*Date of Adoption*]

[1] All parts per million (ppm) emission limits are referenced at 3% volume stack gas oxygen on a dry basis and averaged over 15 minutes.
[2] Percent digester gas is based on the flowrates and higher heating values of the fuels.
[3] All parts per million (ppm) emission limits are referenced at 15% volume stack gas oxygen on a dry basis and averaged over 1 hour.
[4] Percent digester gas is based on volume averaged over a 24 hour period.
[5] All parts per million (ppm) emission limits are referenced at 15% volume stack gas oxygen on a dry basis and averaged over 15 minutes.
[6] Parts per million (ppm) emission limit referenced at 15% volume stack gas oxygen on a dry basis, measured as carbon, and averaged over the sampling time required by the test method.

(2) An owner or operator of a dual fuel boiler simultaneously firing digester gas and more than 10 percent but less than 100 percent natural gas, based on the flowrates and higher heating values of the fuels used, shall comply with the natural gas emission limit in Table 1 or the weighted emission limit calculated by Equation 1. The owner or operator of a boiler using the weighted emission limit shall obtain flowrates and higher heating values by the following methods:

(A) Measure the flow of each fuel used with a non-resettable totalizing fuel flow meter as approved by the Executive Officer, at the time of compliance determination.

(B) Measure the higher heating value of digester gas using a monitoring procedure approved by South Coast AQMD. The digester gas sample used to obtain the higher heating value shall be collected no earlier than 30 days before compliance is determined.

$$\text{Weighted Limit} = \frac{(CL_A \text{ x } Q_A \text{ x } V_A) + (CL_B \text{ x } Q_B \text{ x } V_B)}{(Q_A \text{ x } V_A) + (Q_B \text{ x } V_B)} \qquad \text{(Equation 1)}$$

Where:

CL_A = compliance limit in Table 1 when firing 90% digester gas or more

Q_A = higher heating value of digester gas in Btu per standard cubic foot (scf)

V_A = flowrate of digester gas in scf per unit of time

CL_B = compliance limit in Table 1 when firing 100% natural gas

Q_B = higher heating value of natural gas in Btu per scf

V_B = flowrate of natural gas in scf per unit of time

(3) An owner or operator of a dual fuel turbine simultaneously firing digester gas and more than 40 percent but less than 100 percent natural gas, based on volume averaged over 24 hours, shall comply with the weighted emission limit calculated by Equation 2. The owner or operator of a turbine using the weighted emission limit shall obtain flowrates and higher heating values by the following methods:

(A) Measure the flow of each fuel used with a non-resettable totalizing fuel flow meter as approved by the Executive Officer, at the time of compliance determination.

(B) Measure the higher heating value of the digester gas using a monitoring procedure approved by South Coast AQMD. The digester gas sample used to obtain the higher heating value shall be collected no earlier than 30 days before compliance is determined..

$$\text{Weighted limit} = \frac{\left((CL_A + 18.1) \text{ x } Q_A \text{ x } V_A\right) + (CL_B \text{ x } Q_B \text{ x } V_B)}{(Q_A \text{ x } V_A) + (Q_B \text{ x } V_B)} \quad \text{(Equation 2)}$$

Where:

CL_A = compliance limit in Table 1 when firing 60% digester gas or more

Q_A = higher heating value of digester gas in Btu per scf

V_A = flowrate of digester gas in scf per unit of time

CL_B = compliance limit in Table 1 when firing 100% natural gas

Q_B = higher heating value of natural gas in Btu per scf

V_B = flowrate of natural gas in scf per unit of time

(4) Averaging Times for Units with CEMS

(A) An owner or operator of a boiler shall meet the applicable emission limits specified in Table 1 or paragraph (d)(2), averaged over a fixed interval of 1 clock hour.

(B) An owner or operator of a turbine shall meet the applicable emission limits specified in Table 1 or paragraph (d)(3), averaged over a rolling period of 1 hour.

(C) An owner or operator of an engine shall meet the applicable emission limits specified in Table 1 averaged over one of the following interval periods:

(i) A fixed interval of 1 hour;

(ii) A fixed interval of 24 hours when meeting the emission limits at or below 11 ppmvd for NOx and 250 ppmvd for CO (if CO is selected for averaging), each corrected to 15% oxygen, with the emission limits and averaging time specified in the permit to operate for the engine on or before November 1, 2019; or

(iii) A fixed interval of 48 hours when meeting the emission limits at or below 9.9 ppmvd for NOx and 225 ppmvd for CO (if CO is selected for averaging), each corrected to 15% oxygen, with emission limits and averaging time specified in the permit to operate for the engine.

(5) Startup and Shutdown

An owner or operator of a unit shall meet the following startup and shutdown requirements for that unit, if NOx, CO, or VOC is discharged into the atmosphere in excess of the limits specified in Table 1, paragraph (d)(2), or paragraph (d)(3):

(A) Startup of a boiler shall not exceed the time period necessary for proper operation of the boiler or for temperatures to be reached for the proper operation of the emission control equipment. Startup or shutdown shall not exceed 6 hours.

(B) An owner or operator of a boiler ≥ 5 MMBtu/hr shall submit to the Executive Officer by January 1 of each year, a~~ schedule~~ plan of scheduled startup and shutdown events for that year.

(i) The number of scheduled startups/shutdowns for a boiler ≥ 5 – 40 MMBtu/hr shall not exceed 10 per month.

(ii) The number of scheduled startups/shutdowns for a boiler > 40 MMBtu/hr shall not exceed 10 per year.

(C) An owner or operator of a unit subject to subparagraph (d)(5)(B) shall submit prior notification of scheduled shutdowns and scheduled startups following scheduled shutdowns in a timely manner and form as specified by the Executive Officer. Shutdowns and startups shall~~must~~ be scheduled in pairs with scheduled dates for each. Notification of scheduled startups and shutdowns is required only if an exemption from the emission limit is required. This notification shall contain the following information:

(i) Dates and times of the scheduled startup and shutdown and its duration; and

(ii) Any other process variables that are appropriate as determined by the Executive Officer.

(D) Startup of a turbine shall not exceed the time at which control equipment is properly operating. Startup or shutdown shall not exceed 2 hours for turbines with SCR and shall not exceed 3 hours for turbines without SCR.

(E) For engines:

(i) Startup shall not exceed the time period necessary for operating temperatures to be reached for the proper operation of the emission control equipment, or the tuning of the engine and/or emission control equipment. Startup or shutdown shall not exceed 30 minutes, unless the Executive Officer approves in writing a longer period, not to exceed 2 hours, and that period is specified by permit conditions;

(ii) Startup after an engine overhaul or major repair requiring removal of a cylinder head or for the installation or the replacement of catalytic emission control equipment shall not last longer than 4 operating hours.

(6) An owner or operator of any turbine shall not burn liquid fuel.

(e) Source Testing

An owner or operator of a unit shall meet the following source test requirements:

(1) An owner or operator of a unit shall conduct source tests for the following equipment and applicable pollutants in accordance with the schedule in Table 2.

TABLE 2
SOURCE TESTING SCHEDULE

Equipment Category	**Frequency**	**Pollutant**	**Elapsed Time Prior to Conducting Source Test**[1]
Boilers ≥ 10 MMBtu/hr	Every 3 years from the date the previous source test was required, no later than the last day of the calendar month that the test is due	NOx, CO	At least 250 operating hours or at least 30 calendar days
Boilers < 10 MMBtu/hr and > 2 MMBtu/hr	Every 5 years from the date the previous source test was required, no later than the last day of the calendar month that the test is due	NOx, CO	At least 250 operating hours or at least 30 calendar days
Turbines with output capacity rating ≥ 2.9 MW	Every year from the date the previous source test was required, no later than the last day of the calendar month that the test is due	NOx, CO	At least 40 operating hours or at least 7 calendar days
Turbines with output capacity rating < 2.9 MW	Every 3 years from the date the previous source test was required, no later than the last day of the calendar month that the test is due or every 8,760 operating hours, whichever occurs later	NOx, CO	At least 40 operating hours or at least 7 calendar days
Engines	Every 2 years from the date the previous source test was required, no later than the last day of the calendar month that the test is due, or every 8,760 operating hours, whichever occurs first[2]	NOx, CO, and VOC reported as carbon	At least 40 operating hours or at least 7 calendar days

[1] Elapsed time subsequent to any tuning or servicing, unless tuning or servicing is due to an unscheduled repair.

[2] Frequency may be reduced once every 3 years if the engine has operated less than 2,000 hours since the last source test. If the engine has not been operated before the date a source test is due, the source test shall be conducted by the end of 7 consecutive days or 15 cumulative days of resumed operation. An owner or operator of the engine shall keep sufficient operating records to demonstrate that it meets the requirements for extension of the source testing deadlines.

(2) An owner or operator of any unit previously not required to conduct an initial source test shall conduct a source test within 12 months from [*Date of Adoption*].

(3) An owner or operator shall submit a source test protocol for approval no later than 60 days prior to a scheduled source test date and conduct the source test within 90 days after a written approval of the source test protocol by the Executive Officer is electronically distributed.

(A) An owner or operator of a unit subject to a previously approved source test protocol shall submit a subsequent protocol if the unit has been altered in a manner that requires a permit alteration, if emission limits for the unit have changed since the previous source test, or if requested by the Executive Officer.

(4) An owner or operator shall include in the protocol the name, address and phone number of the unit operator and the South Coast AQMD-approved source testing contractor that will conduct the test(s), the application and permit number(s), a copy of the current valid approved permit, emission limits, a description of the unit(s) to be tested, the test methods and procedures to be used, the number of tests to be conducted and under what loads.

(A) For engines, an owner or operator shall also include in the protocol the required minimum sampling time for the VOC test, based on the analytical detection limit and expected VOC levels. A description of the parameters to be measured in accordance with the Inspection & Monitoring (I&M) plan requirements of this rule shall also be included in the protocol.

(5) No later than 30 days prior to conducting a source test, an owner or operator shall notify the Executive Officer of the scheduled source test date. If a scheduled source test is delayed, an owner or operator shall notify the Executive Officer within 24 hours from the time that an owner or operator knew of the delay. An owner or operator shall provide at least 7 days prior notice of the rescheduled date of the source test or arrange a rescheduled date with the Executive Officer by mutual agreement.

(6) An owner or operator shall conduct the source testing using a South Coast AQMD approved contractor under the Laboratory Approval Program (LAP) according to the procedures in Table 3.

TABLE 3
SOURCE TESTING METHODS

Pollutant	Test Methods
NOx	South Coast AQMD Test Methods 100.1 or 7.1
CO	South Coast AQMD Test Methods 100.1 or 10.1, or EPA Test Method 10
CO_2 and O_2	South Coast AQMD Test Methods 3.1 or 100.1
VOC	South Coast AQMD Test Methods 25.1 or 25.3, excluding ethane and methane

(7) An owner or operator shall provide source testing facilities as follows:

(A) Sampling ports adequate for the applicable test methods. This includes constructing the air pollution control system and stack or duct such that pollutant concentrations can be accurately determined by applicable test methods;

(B) Safe sampling platform(s), scaffolding or mechanical lifts, including safe access, that comply with California General Safety Orders; and

(C) Utilities for sampling and testing equipment.

(8) For boilers and turbines, the LAP contractor conducting the source test shall make emissions determinations in the as-found operating conditions and shall conduct the source test for at least 15 minutes. No compliance determination shall be made during startup, shutdown, or under breakdown conditions.

(9) For engines, the LAP contractor shall conduct source testing for at least 30 minutes during normal operation (actual duty cycle). This test shall not be conducted under a steady-state condition unless it is the normal operation. In addition, the LAP contractor shall conduct source testing for NOx and CO emissions for at least 15 minutes at: an engine's actual peak load, or the maximum load that can be practically achieved during the test; and at actual minimum load, excluding idle, or the minimum load that can be practically achieved during the test. These additional two tests are not required if the permit limits the engine to operating at one defined load, ±10 percent. The LAP contractor shall not conduct any pre-tests for compliance. If an emission exceedance is found during any of the three phases of the test, that phase shall be completed and reported. An operator shall correct the exceedance, and the source test shall be immediately resumed.

(10) An owner or operator shall submit all source test reports, including a description of the unit tested, to the Executive Officer within 60 days of completion.

(11) An owner or operator may use a relative accuracy test audit (RATAs) required by Rules 218 and 218.1, any applicable South Coast AQMD rule for CEMS certification, operation, monitoring, reporting, and notification, 40 CFR Part 75 Subpart E, or 40 CFR Part 60 Appendix B Specification 2, in lieu of a source test for those pollutants monitored by a CEMS and for all operating loads required by the source test, provided that the RATA is conducted within the same calendar year the source test is required.

(f) CEMS

An owner or operator of a unit that meets the criterion in Table 4 shall install, operate, and maintain in calibration a CEMS, or an equivalent verification system, that complies with Rules 218 and 218.1, or any applicable South Coast AQMD rule for CEMS certification, operation, monitoring, reporting, and notification.

TABLE 4
UNITS REQUIRING CEMS

Equipment Type	**Threshold**	**Pollutant(s)**
Boilers	Rated heat input capacity > 40 MMBtu/hr and an annual heat input > 200 x 10^9 Btu per year	NOx
Turbines	Output capacity rating ≥ 2.9 MW	NOx
Engines	Capacity rating ≥ 1000 bhp and operating more than 2 million bhp-hr per calendar year	NOx, CO
	Combined capacity rating ≥ 1500 bhp and a combined fuel usage of > 16 x 10^9 Btu per year, for engines at the same location[1]	

[1] Effective October 1, 2007, engines located within 75 feet of another engine (measured from engine block to engine block) are considered to be at the same location.

(1) An owner or operator of a turbine required to install a CEMS shall also install equipment that measures and records the following:

(A) Flowrate of fuel gases and the ratio of water or steam to fuel added to the combustion chamber or to the exhaust for the reduction of NOx emissions, as applicable;

(B) Elapsed time of operation; and

(C) Turbine output in MW.

(2) An owner or operator of an engine shall meet the following requirements:

(A) A CO CEMS shall not be required for lean-burn engines.

(B) The following engines shall not be counted towards the combined rating of 1500 bhp or greater and combined fuel usage of more than 16 x 10^9 Btu per year (higher heating value) of engines at the same location:

(i) Engines rated at less than 500 bhp;

(ii) Standby engines that are limited by permit conditions to only operate when other primary engines are not operable;

(iii) Engines that are limited by and in compliance with permit conditions to operate less than 1000 hours per year or a fuel usage of less than 8 x 10^9 Btu per year (higher heating value of all fuels used);

(iv) Engines with an output capacity rating ≥1000 bhp and operating more than 2 million bhp-hr per calendar year required to have a CEMS; and

(v) Engines in compliance with permit conditions that limit the simultaneous use of the engines at the same location in a manner to limit the combined rating of all engines in simultaneous operation to less than 1500 bhp.

(C) In lieu of complying with the CEMS requirements of this subdivision, an owner or operator of an engine 1000 bhp or greater and less than 1200 bhp, or engines at the same location with a combined output capacity rating of 1500 bhp or greater and a combined fuel usage of > 16 x 10^9 Btu per year (higher heating value), may alternatively comply with the I&M plan requirements, pursuant to subdivision (g), provided an owner or operator conducts diagnostic emission checks at least weekly or every 150 operating hours, whichever occurs later.

(i) If the engine is found to exceed an applicable NOx or CO limit by a source test or a South Coast AQMD test using a portable analyzer on 3 or more combined occasions in any 12-month period, an owner or operator shall comply with the CEMS requirements of this subdivision and shall submit a CEMS application to the Executive Officer within 6 months of the third exceedance and obtain final approval of the CEMS within 1 year from the initial approval.

(D) An owner or operator of any engine initially exempt from CEMS by the low-use criterion in Table 4 that later exceeds that criterion, shall install CEMS on that engine. The owner or operator shall submit an application for CEMS within 6 months after the conclusion of the first 12-month period for which the engine(s) exceed the criterion, and shall obtain final approval for the CEMS within 1 year from the initial approval.

(E) An owner or operator may take an existing NOx CEMS out of service for up to two weeks (cumulative) in order to modify the CEMS to add CO monitoring.

(F) Notwithstanding the requirements of Rules 218, 218.1, or any applicable South Coast AQMD rule for CEMS certification, operation, monitoring, reporting, and notification, an owner or operator of an engine required to install a CEMS may:

(i) Store data electronically without a strip chart recorder, but there shall be redundant data storage capability for at least 15 days of data. An operator shall demonstrate that both sets of data are equivalent.

(ii) Conduct relative accuracy testing, as required by Rule 218.1, any applicable South Coast AQMD rule for CEMS certification, operation, monitoring, reporting, and notification, or 40 CFR Part 75 Subpart E, on the same schedule for source testing, as specified in Table 2, instead of annually. The minimum sampling time for each test is 15 minutes.

(G) An owner or operator of a new engine shall not install an engine farther than 75 feet from another engine unless the owner or operator demonstrates to the Executive Officer that operational needs or space limitations require it.

(H) An owner or operator of any new engine issued a permit to construct after [*Date of Adoption*] shall comply with the applicable CEMS requirements of this subdivision when engine operation commences.

(g) Inspection and Monitoring (I&M) Plans

An owner or operator of an engine shall comply with the following requirements for submitting I&M plans:

(1) An owner or operator of an engine without a NOx and CO CEMS shall submit to the Executive Officer an I&M plan for approval. One plan application is required for each facility that does not have a NOx and CO CEMS for each engine. If an engine has a NOx CEMS and does not have a CO CEMS, it is subject to this subdivision as it pertains to CO only. The I&M plan shall include all items listed in Attachment 1. An owner or operator may request an alternative item(s) in Attachment 1 that is determined by the Executive Officer to be equivalent in meeting the same objectives.

(A) Upon written approval by the Executive Officer, an owner or operator shall implement the I&M plan as approved.

(B) An owner or operator shall submit an I&M plan for approval to the Executive Officer for a plan revision before any change in I&M plan operations can be implemented. The operator shall apply for a plan revision prior to any change in emission limits or control equipment.

(C) An owner or operator of any new engine issued a permit to construct after [*Date of Adoption*] shall comply with the applicable I&M plan requirements of this subdivision when engine operation commences. If applicable, an owner or operator shall provide the required information in this subdivision to the Executive Officer prior to the issuance of the permit to construct so that the I&M procedures can be included in the permit.

(h) Diagnostic Emission Checks for Boilers and Engines

An owner or operator shall perform diagnostic emissions checks of NOx and CO emissions for pollutants not monitored by a CEMS, with a portable NOx, CO, and oxygen analyzer that is calibrated, maintained and operated in accordance with manufacturers specifications and recommendations and 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, 1146 and 1146.1. The portable analyzer diagnostic emission checks shall only be conducted by a person who has completed an appropriate South Coast AQMD-approved training program in the operation of portable analyzers and has received a certification issued by South Coast AQMD.

(1) Boilers

(A) For boilers greater than or equal to 5 MMBtu/hr, an owner or operator shall perform diagnostic emission checks at least monthly or every 750 boiler operating hours, whichever occurs later. If a boiler is in compliance for 3 consecutive diagnostic emission checks, without any adjustments to the oxygen sensor set points, then the boiler may be checked quarterly or every 2,000 boiler operating hours, whichever occurs later, until the resulting diagnostic emission check exceeds the applicable limit.

(B) For boilers less than 5 MMBtu/hr and greater than 2 MMBtu/hr, an owner or operator shall perform checks at least quarterly or every 2,000 boiler operating hours, whichever occurs later. If a boiler is in compliance for 4 consecutive required diagnostic emission checks, without any adjustments to the oxygen sensor set points, then the boiler may be checked semi-annually or every 4,000 unit operating hours, whichever occurs later, until the diagnostic emission check exceeds the applicable limit.

(C) A diagnostic emission check that finds the emissions in excess of those allowed by this rule or a permit condition shall not constitute a violation of this rule if an owner or operator corrects the problem and demonstrates compliance with another emission check within 72 hours from the time an owner or operator knew of excess emissions, or reasonably should have known, or shutdown the boiler 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 permit condition is a violation.

(2) Engines

An owner or operator shall perform diagnostic emission checks at least weekly or every 150 hours, whichever occurs later. No engine or control system, maintenance or tuning, may be conducted within 72 hours prior to the diagnostic emission check, unless it is an unscheduled, required repair.

(A) If an engine is in compliance for 3 consecutive diagnostic emission checks, without any adjustments to the oxygen sensor set points, then the engine may be checked monthly or every 750 engine operating hours, whichever occurs later, until there is a noncompliant diagnostic emission check or, for rich-burn engines with a catalytic control device that simultaneously reduces emissions of NOx, CO, and VOC, until the oxygen sensor is replaced. When making adjustments to the oxygen sensor set points that are not within 72 hours prior to the diagnostic emission check, returning to a more frequent diagnostic emission check schedule is not required if the engine is in compliance with the applicable emission limits prior to and after the set point adjustments.

(B) For lean-burn engines that have a NOx CEMS, and that are subject to a CO limit more stringent than 2000 ppmvd, an owner or operator shall perform a CO diagnostic emission check at least quarterly, or every 2,000 engine operating hours, whichever occurs later.

(C) For lean-burn engines that have a NOx CEMS and that are not subject to a CO limit more stringent than 2000 ppmvd, diagnostic emission checks are not required.

(D) A diagnostic emission check that finds the emissions in excess of those allowed by this rule or a permit condition shall meet the requirements in subparagraph (k)(1)(A).

(i) Recordkeeping

An owner or operator of a boiler > 2 MMBtu/hr, turbine, or engine, shall keep and maintain all data logs, monitoring records, including CEMS data, source test reports, diagnostic emission checks, maintenance, service and tuning records, and any other information required by this rule, on-site for 5 years. Records shall be made available to the Executive Officer upon request.

(1) Boilers

(A) The owner or operator of a boiler ≥ 5 MMBtu/hr shall maintain and keep records of startup and shutdown events.

(B) The owner or operator of a boiler ≥ 5 MMBtu/hr with CEMS shall keep records of startup and shutdown events that include hour-by-hour fuel gas firing rates, flue gas temperatures, NOx emissions, and any process variables that are appropriate as determined by the Executive Officer, during startup and shutdown periods.

(2) Turbines

(A) An owner or operator shall maintain an operating log that includes total hours of operation, type of fuel used, fuel consumption (cubic feet of gas), cumulative hours of operation to date for the calendar year, and the actual startup and shutdown times on a daily basis.

(B) For emission control systems used to comply with this rule, an owner or operator shall maintain daily records of system operation and maintenance that demonstrates continuous operation and compliance of an emission control device during periods of emission producing activities.

(3) An owner or operator of any engine shall maintain a monthly operating log that includes total hours of operation, type of fuel used, fuel consumption (cubic feet of gas), and cumulative hours of operation since the last source test.

(4) An owner or operator of a unit required to conduct a source test, pursuant to Table 2, shall maintain records of any tuning or servicing of the unit and hours of operation subsequent to any tuning or servicing, until a source test is conducted.

(j) Other Requirements for Boilers

(1) An owner or operator shall not lower the rated heat input capacity of a boiler to less than or equal to 2 MMBtu/hr. The lowered rated heat input capacity shall be based on manufacturer's identification or rating plate or permit condition.

(2) An owner or operator of a boiler less than or equal to 2 MMBtu/hr shall perform maintenance in accordance with the manufacturer's schedule and specifications as identified in a manual and other written materials supplied by the manufacturer or distributor. The owner or operator shall maintain on site a copy of the manufacturer's and/or distributor's written instructions and retain a record of the maintenance activity for a period of 3 years.

(k) Other Requirements for Engines

(1) Requirements for responding to, diagnosing and correcting breakdowns, faults, malfunctions, alarms, diagnostic emission checks finding emissions in excess of rule or permit limits, and parameters out-of-range.

(A) For any diagnostic emission check or breakdown that results in emissions in excess of those allowed by this rule or a permit condition, an owner or operator shall correct the problem as soon as possible and demonstrate compliance with another diagnostic emission check, or shutdown an engine by the end of an operating cycle, or within 24 hours from the time the owner or operator knew of the breakdown or excess emissions, or reasonably should have known, whichever is sooner.

(B) For excess emissions due to breakdowns that result in NOx or CO emissions greater than the concentrations specified in Table 5, an owner or operator shall not be considered in violation of this rule if the operator demonstrates the all of the following: (1) compliance with subparagraph (k)(1)(A), (2) compliance with the reporting requirements of paragraph (k)(4), and (3) the engine with excess emissions has no more than 3 incidences of breakdowns with emissions exceeding Table 5 limits in the calendar quarter.

TABLE 5
EXCESS EMISSION CONCENTRATION THRESHOLDS FOR BREAKDOWNS

Equipment Category	NOx (ppmvd)[1]	CO (ppmvd)[1]
Lean-Burn Engines	45	250
Rich-Burn Engines	150	2000

1 Corrected to 15% oxygen.

(C) Any emission check conducted by South Coast AQMD staff that finds excess emissions will be treated as a violation.

(D) For other problems, such as parameters out-of-range, an owner or operator shall correct the problem and demonstrate compliance with another diagnostic emission check within 48 hours of the owner or operator first knowing of the problem.

(2) An owner or operator shall maintain an operational non-resettable totalizing time meter to determine the engine elapsed operating time.

(3) An owner or operator of a spark-ignited engine without a Rule 218-approved CEMS shall maintain the air-to-fuel ratio controller and oxygen sensor and feedback control system, or other equivalent technology approved by the Executive Officer, CARB, and EPA.

(4) Reporting Requirements

(A) An owner or operator shall report to the Executive Officer, by telephone (1-800-CUT-SMOG or 1-800-288-7664) or other South Coast AQMD-approved method, any breakdown resulting in emissions in excess of rule or permit emission limits within 1 hour of such noncompliance or within 1 hour of the time the owner or operator knew or reasonably should have known of its occurrence. Such report shall identify the time, specific location, equipment involved, responsible party to contact for further information, and to the extent known, the causes of the noncompliance, and the estimated time for repairs. In the case of emergencies that prevent a person from reporting all required information within the 1-hour limit, the Executive Officer may extend the time for the reporting of required information provided the owner or operator has notified the Executive Officer of the noncompliance within the 1-hour limit.

(B) Within 7 calendar days after the reported breakdown has been corrected, but no later than 30 calendar days from the initial date of the breakdown, unless an extension has been approved in writing by the Executive Officer, an owner or operator shall submit a written breakdown report to the Executive Officer which includes:

(i) An identification of the equipment involved in causing, or suspected of having caused, or having been affected by the breakdown;

(ii) The duration of the breakdown;

(iii) The date of correction and information demonstrating that compliance is achieved;

(iv) An identification of the types of excess emissions, if any, resulting from the breakdown;

(v) A quantification of the excess emissions, if any, resulting from the breakdown and the basis used to quantify the emissions;

(vi) Information substantiating whether the breakdown resulted from operator error, neglect or improper operation or maintenance procedures;

(vii) Information substantiating that steps were immediately taken to correct the condition causing the breakdown, and to minimize the emissions, if any, resulting from the breakdown;

(viii) A description of the corrective measures undertaken and/or to be undertaken to avoid such a breakdown in the future; and

(ix) Pictures of any equipment which failed, if available.

(C) Within 15 days of the end of each calendar quarter, an owner or operator shall submit to the Executive Officer a report that lists each occurrence of a breakdown, fault, malfunction, alarm, engine or control system operating parameter out of the acceptable range established by an I&M plan or permit condition, or a diagnostic emission check that finds excess emissions. Such report shall be in a South Coast AQMD-approved format, and for each incident shall identify the time of the incident, the time the operator learned of the incident, specific location, equipment involved, responsible party to contact for further information, to the extent known the causes of the event, the time and description of corrective actions, including shutting an engine down, and the results of all portable analyzer NOx and CO emissions checks done before or after the corrective actions. An owner or operator shall also report if no incidents occurred.

(l) Schedule for Permit Revisions

(1) No later than the date a facility's next Title V permit renewal application is due, an owner or operator of a Title V facility shall submit applications for each existing unit subject to this rule, and applications for I&M plans, if applicable.

(2) An owner or operator of a non-Title V facility shall:

(A) Submit an application for each existing boiler > 2 MMBtu/hr subject to this rule on or before January 1, 2023.

(B) Submit an application for each existing boiler ≤ 2 MMBtu/hr subject to this rule on or before July 1, 2023.

(C) Submit an application for each existing engine subject to this rule and an I&M plan application for each facility with an existing engine subject to this rule on or before January 1, 2024.

(D) Submit an application for each existing turbine subject to this rule on or before July 1, 2024.

(m) Exemptions

(1) The emission limits in Table 1 or paragraph (d)(2) of this rule do not apply to any boiler 5 MMBtu/hr or greater in operation prior to September 5, 2008 with an annual heat input of less than or equal to 90,000 therms per year. An owner or operator of such boiler shall not operate the boiler in a manner that exceeds NOx emissions of 30 ppm corrected to three percent oxygen on a dry basis. In

lieu of complying with the applicable emission limits specified in Table 1 or paragraph (d)(2), the owner or operator shall:.

(A) Tune the unit(s) at least twice per year, (at intervals from four to eight months apart) in accordance with the procedure described in Attachment 2 or the unit manufacturer's specified tune-up procedure. If a different tune-up procedure from that described in Attachment 2 is used then a copy of this procedure shall be kept on site. 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. If the unit does not operate throughout a continuous 6-month period within a 12-month period, only one tune-up is required for the 12-month period that includes the entire period of non-operation. For this case, the tune-up shall be conducted within 30 days of startup. No tune-up is required during a rolling 12-month period for any unit that is not operated during that rolling 12-month period; this unit may be test fired to verify availability of the units for its intended use but once the test firing is completed the unit shall be shutdown. Records of test firings shall be maintained for a rolling 24-month period, and shall be made accessible to an authorized South Coast AQMD representative upon request.

(B) Any boiler subject to the requirements specified in paragraph (m)(1) that exceeds 90,000 therms of annual heat input from all fuels used shall constitute a violation of this rule. In addition, the owner or operator shall:

(i) Within four months after exceeding 90,000 therms of annual heat input, submit required applications for permits to construct and operate; and

(ii) Within 18 months after exceeding 90,000 therms of annual heat input, demonstrate and maintain compliance with all applicable requirements of this rule.

(2) An owner or operator of any turbine ≥ 0.3 MW claiming any of the following exemptions shall provide verification of meeting the applicable criteria. All records shall be kept on-site for 5 years and made available to South Coast AQMD staff upon request.

(A) The provisions of this rule shall not apply to turbines operated exclusively for firefighting and/or flood control.

(B) A turbine that operates only as a power source for a facility when the primary power source has been rendered inoperable, except it may not be used for power interruption pursuant to an interruptible power supply agreement, shall not be subject to the provisions of this rule, provided that an owner or operator:

(i) Installs and maintains in proper operation a non-resettable engine hour meter;

(ii) Maintains an operating log that includes, on a daily basis, the total hours of operation, type and quantity of fuel used, cumulative hours of operation to date for the calendar year, and the actual startup and shutdown times; and

(iii) Demonstrates a usage of less than 200 hours of operation per calendar year.

(C) If the hour-per-year limit in clause (m)(2)(B)(iii) is exceeded, the exemption shall be automatically and permanently withdrawn, and the owner or operator shall:

(i) Notify the Executive Officer within 7 days of the date the hour-per-year limit is exceeded; and

(ii) Within 30 days after the date the hour-per-year limit is exceeded, submit a permit application for modification to equipment to meet the applicable compliance limit within 24 months of the date the hour-per-year limit is exceeded. Included with this permit application, an owner or operator shall submit an emission control plan including a schedule of increments of progress for the installation of the required control equipment. This plan shall be subject to the review and approval of the Executive Officer.

(3) This rule does not apply to any boiler, turbine < 0.3 MW, or engine that is not permitted to fire digester gas or digester gas and another fuel. An owner or operator of a boiler or engine permitted to fire exclusively non-digester gas fuels shall comply with the following rules:

(A) For boilers, Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional and Commercial Boilers, Steam Generators, and Process Heaters, Rule 1146.1 – Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, and Rule 1146.2 – Emission of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters; and

(B) For engines, Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines.

(4) This rule does not apply to emergency standby engines, engines used for fire-fighting and flood control, and any other emergency engines approved by the Executive Officer, which have permit conditions that limit operation to 200 hours or less per year as determined by an elapsed operating time meter, provided that an owner or operator:

(A) Installs and maintains in proper operation a non-resettable engine hour meter; and

(B) Maintains an operating log that includes cumulative hours of operation to date for the calendar year.

(5) This rule does not apply to:

(A) Laboratory engines used in research and testing purposes;

(B) Engines operated for purposes of performance verification and testing of engines;

(C) Auxiliary engines used to power other engines or gas turbines during start-ups;

(D) Portable engines that are registered under the state registration program pursuant to Title 13, Article 5 of the CCR;

(6) This rule does not apply to any turbine < 0.3 MW that was in operation prior to May 3, 2013.

(7) The emission limits in Table 1 or paragraph (d)(2) do not apply to any existing boiler ≤ 2 MMBtu/hr without a NOx concentration limitation specified in the permit.

(8) The emission limits in Table 1 or paragraph (d)(3) do not apply to the initial commissioning of a new engine or turbine for the period specified by permit conditions.

(A) The commissioning of a new engine shall not exceed 150 operating hours.

(B) The commissioning of a new turbine shall not exceed 150 operating hours, unless the Executive Officer approves in writing a longer time period and that time period is specified in the permit to operate.

(9) The natural gas emission limits in Table 1 do not apply to boilers ≤ 2 MMBtu/hr that are demonstrated to use less than 9,000 therms of natural gas during every

calendar year. Compliance with the exemption limit shall be demonstrated by a calculation based on the annual fuel consumption recorded by an in line fuel meter or the annual operating hours recorded by a timer and using one of the following methods.

(A) Annual therm usage recorded by fuel meter and corrected to standard pressure; or

(B) Amount of fuel (i.e., in thousand cubic feet of gas corrected to standard pressure) converted to therm using the higher heating value of the fuel; or

(C) Annual therm usage calculated by multiplying the number of hours fuel is burned by the rated heat input capacity of the unit converted to therms.

(10) This rule shall not apply to engines owned and operated by San Bernardino City Municipal Water Department that are subject to the variance issued by the South Coast Air Quality Management District Hearing Board on December 20, 2018 during the term of that variance. The engines shall remain subject to Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines and the variance for its duration.

ATTACHMENT 1

An I&M plan submitted to the Executive Officer for approval and implementation shall include:

A. Identification of engine and control equipment operating parameters necessary to maintain pollutant concentrations within the rule and permit limits. This shall include, but not be limited to:

1. Procedures for using a portable NOx, CO and oxygen analyzer to establish the set points of the air-to-fuel ratio controller (AFRC) at 25%, 60%and 95% load (or fuel flow rate), ± 5%, or the minimum, midpoint and maximum loads that actually occur during normal operation, ± 5%, or at any one load within the ± 10% range that an engine permit is limited to in accordance with (h)(2)(C)(ii) of the rule;
2. Procedures for verifying that the AFRC is controlling the engine to the set point during the daily monitoring required by subdivision D of this attachment;
3. Procedures for reestablishing all AFRC set points with a portable NOx, CO and oxygen analyzer whenever a set point must be readjusted, within 24 hours of an oxygen sensor replacement, and, for rich-burn engines with a catalytic control device that simultaneously reduces emissions of NOx, CO, and VOC, between 100 and 150 engine operating hours after an oxygen sensor replacement;
4. For engines with catalysts, the maximum allowed exhaust temperature at the catalyst inlet, based on catalyst manufacturer specifications;
5. For lean-burn engines with SCR, the minimum exhaust temperature at the catalyst inlet required for reactant flow (ammonia or urea), and procedures for using portable NOx and oxygen analyzer to establish the acceptable range of reactant flow rate, as a function of load.

Parameter monitoring is not required for diesel engines without exhaust gas recirculation and catalytic exhaust control devices.

B. Procedures for alerting the operator to emission control malfunctions. Engine control systems, such as air-to-fuel ratio controllers, shall have a malfunction indicator light and audible alarm.

C. Procedures for diagnostic emission checks conducted by a portable NOx, CO, and oxygen analyzer per the requirements of clause (h)(2)(D)(ii) of the rule.

D. Procedures for at least daily monitoring, inspection and recordkeeping of:

1. engine load or fuel flow rate;
2. the set point, maximums and acceptable ranges of the parameters identified by subdivision A of this attachment, and the actual values of the same parameters;
3. the engine elapsed time meter operating hours;
4. the operating hours since the last diagnostic emission check required by clause (h)(2)(D)(ii) of the rule;
5. for rich-burn engines with three-way catalysts, the difference of the exhaust temperatures (ΔT) at the inlet and outlet of the catalyst (changes in the ΔT can indicate changes in the effectiveness of the catalyst);
6. engine control system and AFRC system faults or alarms that affect emissions.

The daily monitoring and recordkeeping may be done in person by the operator, or by remote monitoring.

E. Procedures for responding to, diagnosing and correcting breakdowns, faults, malfunctions, alarms, diagnostic emission checks finding emissions in excess of rule or permit limits, and parameters out-of-range, per the requirements of clause (h)(2)(D)(iii) of the rule.

F. Procedures and schedules for preventative and corrective maintenance.

G. Procedures for reporting noncompliance to the Executive Officer in accordance with subparagraph (h)(2)(H) of the rule.

H. Procedures and format for the recordkeeping of monitoring and other actions required by the plan.

ATTACHMENT 2

A. Equipment Tuning Procedure[1] for Forced-Draft Boilers, Steam Generators, and Process Heaters.

Nothing in this Equipment Tuning Procedure shall be construed to require any act or omission that would result in unsafe conditions or would be in violation of any regulation or requirement established by Factory Mutual, Industrial Risk Insurers, National Fire Prevention Association, the California Department of Industrial Relations (Occupational Safety and Health Division), the Federal Occupational Safety and Health Administration, or other relevant regulations and requirements.

Should a different tuning procedure be used, a copy of this procedure should be kept with the unit records for two years and made available to the South Coast AQMD personnel on request.

1. Operate the unit at the firing rate most typical of normal operation. If the unit experiences significant load variations during normal operation, operate it at its average firing rate.
2. At this firing rate, record stack gas temperature, oxygen concentration, and CO concentration (for gases fuels) or smoke-spot number[2] (for liquid fuels), and observe flame conditions after unit operation stabilizes at the firing rate selected. If the excess oxygen in the stack gas at the lower end of the range of typical minimum values[3], and if CO emissions are low and there is not smoke, the unit is probably operating at near optimum efficiency - at this particular firing rate.
3. Increase combustion air flow to the furnace until stack gas oxygen levels increase by one to two percent over the level measured in Step 2. As in Step 2, record the stack gas temperature, CO concentration (for gaseous fuels) or smoke-spot number (for liquid fuels), and observed flame conditions for these higher oxygen levels after boiler operation stabilizes.

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[1] This tuning procedure is based on a tune-up procedure developed by KVB, Inc. for the United States EPA

[2] The smoke-spot number can be determined with ASTM Test Method D-2156 or with the Bacharach method. ASTM Test Method D-2156 is included in a tuneup kit that can be purchased from the Bacharach Company.

[3] Typical minimum oxygen levels for boilers at high firing rates are:

1. For natural gas: 0.5% - 3%
2. For liquid fuels: 2% - 4%

However, complete the remaining portion of this procedure to determine whether still lower oxygen levels are practical.

4. Decrease combustion air flow until the stack gas oxygen concentration is at the level measured in Step 2. From this level gradually reduce the combustion air flow, in small increments. After each increment, record the stack gas temperature, oxygen concentration, CO concentration (for gaseous fuels) and smoke-spot number (for liquid fuels). Also observe the flame and record any changes in its condition. Also observe the flame and record any changes in its condition.
5. Continue to reduce combustion air flow stepwise, until one of these limits reached:
   a. Unacceptable flame conditions – such as flame impingement on furnace walls or burner parts, excessive flame carryover, or flame instability.
   b. Stack gas CO concentrations greater than 400 ppm
   c. Smoking at the stack
   d. Equipment-related limitations – such as low windbox/furnace pressure differential, built in air-flow limits, etc.
6. Develop an O_2/CO curve (for gaseous fuels) or O_2/smoke curve (for liquid fuels) similar to those shown in Figures 1 and 2 using the excess oxygen and CO or smoke-spot number data obtained at each combustion air flow setting.

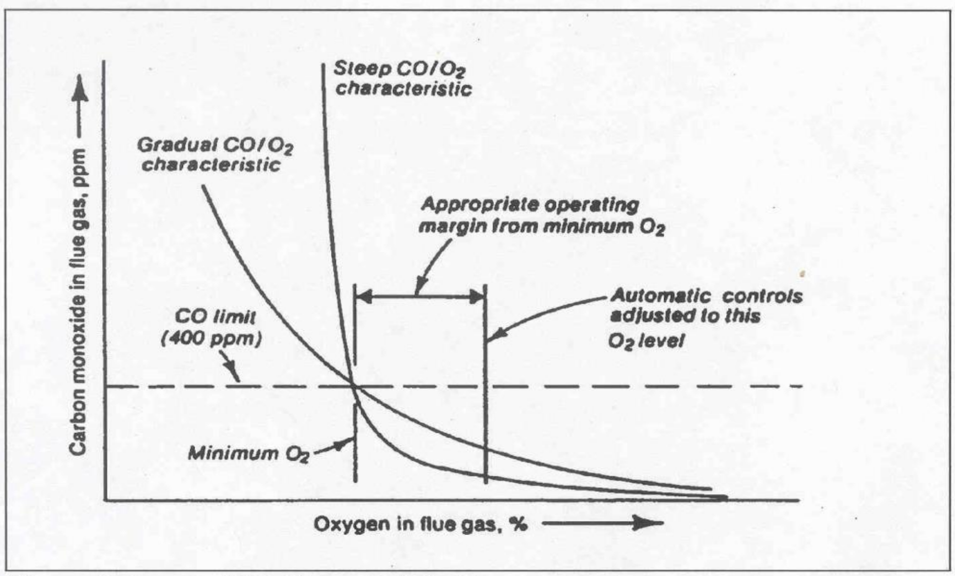

Figure 1 Oxygen/CO Characteristic Curve

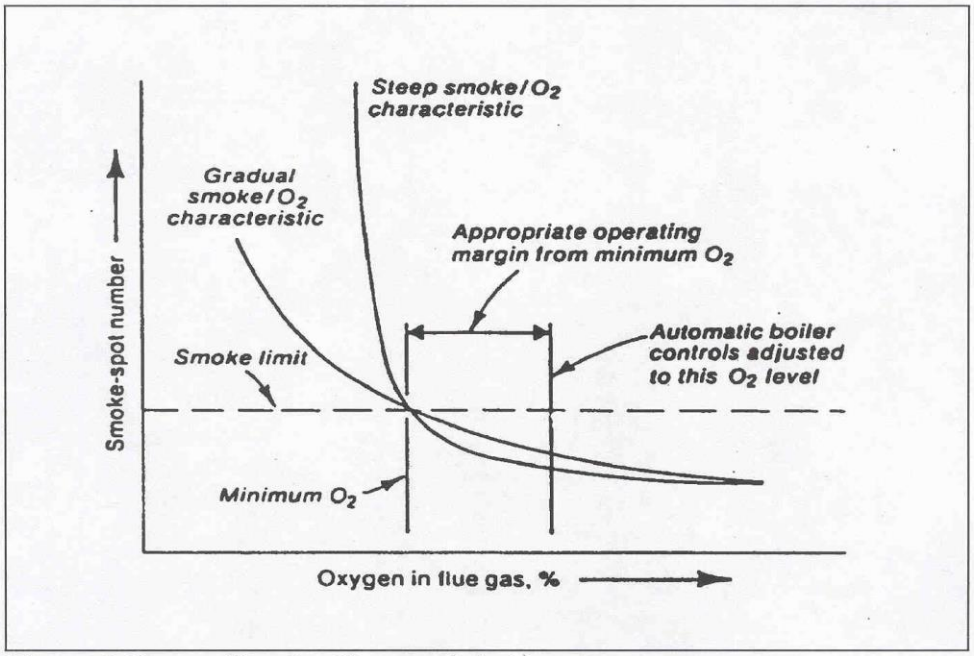

Figure 2 Oxygen/Smoke Characteristic Curve

7. From the curves prepared in Step 6, find the stack gas oxygen levels where the CO emissions or smoke-spot number equal the following values:

<u>Fuel</u>	<u>Measurement</u>	<u>Value</u>
Gaseous	CO Emissions	400 ppm
#1 and #2 oils	smoke-spot number	number 1
#4 oil	smoke-spot number	number 2
#5 oil	smoke-spot number	number 3
Other oils	smoke-spot number	number 4

The above coniditions are referred to as the CO or smoke thresholds, or as the minimum excess oxygen level.

Compare this minimum value of excess oxygen to the expected value provided by the combustion unit manufacturer. If the minimum level found is substanitally higher than the value provided by the combustion unit manufacturer, burner adjustments can probably be made to improve fuel and air mixing, thereby allowing operation with less air.

8. Add 0.5 to 2.0 percent O_2 to the minimum excess oxygen level found in Step 7 and reset burner controls to operate automatically at this higher stack gas oxygen level. This margin above the minimum oxygen level accounts for fuel variations,

variations in atmospheric conditions, load changes, and nonrepeatability or play in automatic controls.

9. If the load of the combustion unit varies significantly during normal operation, repeat Steps 1-8 for firing rates that represent the upper and lower limits of the range of the load. Because control adjustments at one firing rate may affect conditions at other firing rates, it may not be possible to establish the optimum excess oxygen level at all firing rates. If this is the case, choose the burner control settings that give best performance over the range of firing rates. If one firing rate predominates, settings should optimize conditions at that rate.
10. Verify that the new settings can accommodate the sudden load changes that may occur in daily operation without adverse effects. Do this by increasing and decreasing load rapidly while observing the flame and stack. If any of the conditions in Step 5 result, reset the combustion controls to provide a slightly higher level of excess oxygen at the affected firing rates. Next, verify these new settings in a similar fashion. Then make sure that the final control settings are recorded at steady-state operating conditions for future reference.
11. When the above checks and adjustments have been made, record data and attach combustion analysis data to boiler, steam generator, or heater records indicating name and signature of person, title, and the date the tune up was performed

B. Equipment Tuning Procedure for natural Draft-Fired Boilers, Steam Generators, and Process Heaters.

Nothing in this Equipment Tuning Procedure shall be construed to require any act or omission that would result in unsafe conditions or would be in violation of any regulation or requirement established by Factory Mutual, Industrial Risk Insurers, National Fire Prevention Association, the California Department of Industrial Relations (Occupational Safety and Health Division), the Federal Occupational Safety and Health Administration, or other relevant codes, regulations and equipment manufacturers specifications and operating manuals.

Should a different tuning procedure be used, a copy of this procedure should be kept with the unit records for two years and made available to the South Coast AQMD personnel on request.

1. **PRELIMINARY ANALYSIS**

   a. CHECK THE OPERATING PRESSURE OR TEMPERATURE.

   Operate the boiler, steam generator, or heater at the lowest acceptable pressure or temperature that will satisfy the load demand. This will minimize heat and radiation losses. Determine the pressure or temperature that will be used as a basis for comparative combustion analysis before and after tuneup.

b. CHECK OPERATING HOURS.
Plan the workload so that the boiler, steam generator, or process heater operates only the minimum hours and days necessary to perform the work required. Fewer operating hours will reduce fuel use and emissions. For units requiring a tuneup to comply with the rule, a totalizing non-resettable fuel meter will be required for each fuel used and for each boiler, steam generator, and heater to prove fuel consumption is less than the heat input limit in therms per year specified in the rule.

c. CHECK AIR SUPPLY.
Sufficient fresh air supply is essential to ensure optimum combustion and the area of air supply openings must be in compliance with applicable codes and regulations. Air openings must be kept wide open when the burner is firing and clear from restriction to flow.

d. CHECK VENT
Proper venting is essential to assure efficient combustion. Insufficient draft or overdraft promotes hazards and inefficient burning. Check to be sure that vent is in good condition, sized properly and with no obstructions.

e. COMBUSTION ANALYSIS
Perform an “as is” combustion analysis (CO, O_2, etc.) with a warmed up unit at high and low fire, if possible. In addition to data obtained from combustion analysis, also record the following:

i. Inlet fuel pressure at burner (at high & low fire)

ii. Draft at inlet to draft hood or barometer damper

1) Draft hood: high, medium, and low

2) Barometric Damper: high, medium, and low

iii. Steam pressure, water temperature, or process fluid pressure or temperature entering and leaving the boiler, steam generator, or process heater.

iv. Unit rate if meter is available.

With above conditions recorded, make the following checks and corrective actions as necessary:

2. **CHECKS & CORRECTIONS**

a. CHECK BURNER CONDITION.
Dirty burners or burner orifices will cause boiler, steam generator, or process heater output rate and thermal efficiency to decrease. Clean burners and burner orifices thoroughly. Also, ensure that fuel filters and moisture traps are in place, clean, and operating properly, to prevent plugging of gas orifices. Confirm proper location and orientation of burner diffuser spuds, gas canes, etc. Look for any burned-ff or missing burner parts, and replace as needed.

b. CHECK FOR CLEAN BOILER, STEAM GENERATOR, OR PROCESS HEATER TUBES & HEAT TRANSFER SURFACES.
External and internal build-up of sediment an scale on the heating surfaces creates an insulating effect that quickly reduces unit efficiency. Excessive fuel cost will result if the unit is not kept clean. Clean tube surfaces, remove scale and soot, assure proper process fluid flow and flue gas flow.

c. CHECK WATER TREATMENT & BLOWDOWN PROGRAM.
Soft water and the proper water or process fluid treatment must be uniformly used to minimize scale and corrosion. Timely flushing and periodic blowdown must be employed to eliminate sediment and scale build-up on a boiler, steam generator or process heater.

d. CHECK FOR STEAM, HOT WATER OR PROCESSFLUID LEAKS.
Repair all leaks immediately since even small high-pressure leaks quickly lead to considerable fuel, water and steam losses. Be sure there are no leaks through the blow-off, drains, safety valve, by-pass lines or at the feed pump, if used.

3. **SAFETY CHECKS**

a. Test primary and secondary low water level controls.

b. Check operating and limit pressure and temperature controls.

c. Check pilot safety shut off operation.

d. Check safety valve pressure and capacity to meet boiler, steam generator or process heater requirements.

e. Check limit safety control and spill switch.

4. **ADJUSTMENTS**

While taking combustion readings with a warmed up boiler, steam generator, or process heater at high fire perform checks and adjustments as follows:

a. Adjust unit to fire at rate; record fuel manifold pressure.

b. Adjust draft and/or fuel pressure to obtain acceptable, clean combustion at both high, medium and low fire. Carbon Monoxide CO value should always be below 400 parts per million (PPM) at 3% O_2. If CO is high make necessary adjustments.

   Check to ensure boiler, steam generator, or process heater light offs are smooth and safe. A reduced fuel pressure test at both high and low fire should be conducted in accordance with the manufacturer's instructions and maintenance manuals.

c. Check and adjust operation of modulation controller. Ensure proper, efficient and clean combustion through range of firing rates.

When above adjustments and corrections have been made, record all data.

5. **FINAL TEST**

Perform a final combustion analysis with a warmed up boiler, steam generator, or process heater at high, medium and low fire, whenever possible. In addition to data from combustion analysis, also check and record:

a. Fuel pressure at burner (High, Medium, and Low).

b. Draft above draft hood or barometric damper (High, Medium, and Low).

c. Steam pressure or water temperature entering and leaving boiler, steam generator, or process heater.

d. Unit rate if meter is available.

When the above checks and adjustments have been made, record data and attach combustion analysis data to boiler, steam generator, or process heater records indicating name and signature of person, title, company name, company address and date the tuneup was performed.

ATTACHMENT G

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Staff Report
Proposed Rule 1179.1 – ~~NOx~~ Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities

October 2020

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WAYNE NASTRI

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EXECUTIVE SUMMARY

Publicly owned treatment works (POTWs) are facilities that treat municipal wastewater. A POTW is defined as a wastewater treatment or reclamation plant, either owned or operated by a public entity, including all operations within the boundaries of the wastewater and sludge treatment plant. POTWs treat sewage water with a multi-stage process, which includes anaerobic digestion where organic solids are broken down by microorganisms, before discharging water from the facility. This process produces a byproduct called digester gas, a form of biogas. Digester gas differs from other process gases because of the specific contaminants found in wastewater. Digester gas is used to fuel combustion equipment that provides heat or power for processes within the POTW.

During the rulemaking for the December 2018 amendments for Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters (Rule 1146), Rule 1146.1 - Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters (Rule 1146.1), and Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters (Rule 1146.2), the South Coast AQMD received comments describing the unique challenges faced by POTWs associated with digester gas and how POTWs provide essential public services. Staff recommended to separate provisions for combustion equipment at POTWs (and at landfills, which face similar challenges and will be subject to a separate rulemaking). Proposed Rule 1179.1 - ~~NOx~~ Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities (PR 1179.1) was developed to establish Best Available Retrofit Control Technology (BARCT) requirements for combustion equipment located at POTWs using digester gas and contain provisions applicable to POTWs in one rule.

A total of 86 biogas fueled boilers, turbines, and engines, at 30 facilities will be affected by PR 1179.1. Oxides of nitrogen (NOx), carbon monoxide (CO), and volatile organic compound (VOC) limitations are contained in PR 1179.1 for applicable equipment categories. <u>Emission limits for boilers and engines are the same as existing limits that POTWs are currently required to meet under existing source-specific rules. Turbines are currently exempt from Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines which is the source-specific rule that establishes NOx and CO emission limits for turbines. As a result</u>~~However~~, turbines greater than or equal to 0.3 MW <u>will be</u>~~are the only equipment category~~ required by PR 1179.1 to meet lower NOx emission limits. ~~Boilers, turbines less than 0.3 MW, and engines will be subject to NOx emission limitations that are the same as those contained in current applicable source-specific rules or current equipment permits.~~ The proposed NOx emission limit of 18.8 ppm at 15 percent oxygen on a dry basis for turbines greater than or equal to 0.3 MW will reduce NOx emissions by 0.05 tpd[1]. <u>Turbines less than 0.3 MW will be required to meet the proposed emission limit of 9 ppm at the time of adoption which is consistent with current permit limits.</u> The cost-effectiveness for turbines to meet 18.8 ppm at rule adoption is $48,600 per ton of NOx reduced[2]. Facilities would also be required to revise equipment permits to reflect the applicability of PR 1179.1. Including

[1] Reductions calculated are based on current permitted concentration emission levels and proposed emission limit.
[2] Reductions calculated as part of the cost-effectiveness determination are based on current concentration emission levels of the turbines as demonstrated in recent source tests.

the costs for permit revisions, the total cost-effectiveness to implement PR 1179.1 is approximately $50,000 per ton of NOx reduced.

PR 1179.1 was developed through a public process. Five Working Group meetings were held on: May 2, 2019, August 13, 2019, November 6, 2019, February 12, 2020, and June 4, 2020. Working Group meetings include affected businesses, environmental and community representatives, public agencies, consultants, and other interested parties. The purpose of the Working Group meetings is to discuss details of proposed amendments and to listen to concerns and issues with the objective to build consensus and resolve issues.

In addition, a Public Workshop was held on July 22, 2020. The purpose of the Public Workshop is to present the proposed rule language to the general public and to stakeholders, as well as to solicit comments.

CHAPTER 1: BACKGROUND

BACKGROUND

Publicly owned treatment works (POTWs) treat municipal wastewater. A POTW is defined as a wastewater treatment or reclamation plant, either owned or operated by a public entity, including all operations within the boundaries of the wastewater and sludge treatment plant. POTWs treat sewage water with a multi-stage process before discharging water from the facility. The treatment process involves anaerobic digestion where organic solids are broken down by microorganisms. This process produces a byproduct called digester gas, a form of biogas. Digester gas differs from other process gases because of the specific contaminants found in wastewater. Digester gas is used to fuel combustion equipment that provides heat or power for processes within the POTW. If a facility produces excess digester gas or does not have equipment that can utilize produced digester gas, the facility is forced to flare the digester gas. Flaring excess gas is recognized as an important aspect of maintaining safety but it is preferred for facilities to implement projects that beneficially use digester gas, such as combustion equipment or fuel cells.

During the rulemaking for the December 2018 amendments for Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters (Rule 1146), Rule 1146.1 - Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters (Rule 1146.1), and Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters (Rule 1146.2), the South Coast AQMD received comments describing the unique challenges faced by POTWs associated with digester gas and how POTWs provide essential public services. As a result, staff recommended to separate provisions for combustion equipment at POTWs and landfills, as landfills have similar challenges associated with digester gas as POTWs. Proposed Rule 1179.1 - ~~NOx~~ Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities (PR 1179.1) was developed to establish Best Available Retrofit Control Technology (BARCT) requirements for combustion equipment located at POTWs and to contain provisions specific to equipment located at POTWs in one rule. Staff identified characteristics of POTWs that required consideration throughout the rule development. These unique characteristics include the composition of the digester gas, the use of digester gas, the potential impacts of statewide legislation including Senate Bill (SB) 1383, and the challenges unique to public entities, including financial constraints and the public planning process.

Digester Gas

Digester gas at POTWs is primarily produced from solid organic waste in wastewater but can also be produced from food waste. Digester gas produced by the digestion of solid organic waste found in wastewater has a lower Btu content (higher heating value) than that of natural gas. Btu content has been reported in the range of 550-650 Btu/scf for digester gas produced by facilities in the South Coast AQMD, whereas natural gas has a higher heating value of approximately 1050 Btu/scf. Another significant difference between digester gas and natural gas or other conventional fuels is the presence of siloxanes and high levels of undesirable compounds such as hydrogen sulfide (H_2S).

The presence of siloxanes in gas streams can affect combustion processes if not properly maintained. When siloxane compounds are combusted, silicon dioxide is formed. This glass-like compound forms deposits on components of combustion equipment, increasing maintenance, and if not maintained, can damage combustion equipment. Siloxane presence in digester gas streams can also damage post-combustion equipment, specifically, selective catalytic reduction (SCR) units. SCR catalyst functionality is severely hindered by siloxanes. Siloxanes can deactivate the catalyst of the SCR, causing the SCR to be ineffective for reducing NOx. To minimize~~resolve~~ this problem, facilities use gas cleaning technology to remove siloxanes before combustion. However, inadequate cleaning of the digester gas can foul~~could cause the facility to change out~~ the SCR catalyst~~ more frequently~~, increasing operating and maintenance costs.

SB 1383

SB 1383 - Short-Lived Climate Pollutants; Methane Emissions: Dairy and Livestock; Organic Waste: Landfills was approved on September 19, 2016, and is intended to regulate greenhouse gas emissions by requiring food waste to be diverted from landfills and processed elsewhere. POTWs offer an alternative to landfills for accepting food waste. Acceptance of food waste at POTWs varies, with some POTWs currently accepting food waste and possibly increasing acceptance, some that are currently not accepting food waste that have plans to begin accepting food waste, and some that currently do not and do not have plans to accept food waste in the future. POTWs have commented as part of the work for Rule 1118.1 for non-refinery flares that SB1383 is anticipated to~~may~~ increase~~ use of~~ digester gas generation at POTWs. Although digester gas generation ~~it~~ is expected to increase, the impact of large-scale food waste processing at POTWs remains unclear.

Financial Challenges and the Public Planning Process

POTWs experience challenges that private industries do not experience. POTW projects are subject to a structured procurement process. New projects require approval from governing bodies which may be by city council, board of directors, or board of county supervisors, for example. Securing the financial means for a project to comply with regulations may be more difficult for an essential public service than for private industry. POTWs are public service providers and do not manufacture products for sale. To recover costs of implementing a control project, POTWs may need to increase utility rates for the consumer. Increased costs for a public utility may be difficult for POTWs to impose.

REGULATORY HISTORY

Combustion equipment located at POTWs are currently regulated under the following source-specific rules. NOx and CO emissions from boilers, process heaters and steam generators are regulated under Rules 1146, 1146.1, and 1146.2. This series of rules includes emission limits for all fuels, including digester gas. Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines (Rule 1134) applied to turbines that were in operation before 1989. The six turbines located at POTWs were not in operation before 1989. Rule 1134 was amended on April 5, 2019 and excluded turbines located at POTWs considering Proposed Rule 1179.1 was in development. Rule 1134 contains emission limits for all fuels, but does not apply to equipment located at POTWs or landfills. NOx, VOC, and CO emissions from engines are regulated under Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines (Rule 1110.2). Rule 1110.2 contains emission limits for all gaseous and liquid fuels, including digester gas. Table 1-1~~2~~ lists the combustion equipment located at POTWs and applicable rules.

TABLE 1-1
RULES APPLICABLE TO COMBUSTION EQUIPMENT AT POTWS

Equipment	South Coast AQMD Rule	General Provisions
Boilers > 2 MMBtu/hr	Rules 1146 and 1146.1 (NOx and CO)	Natural gas and digester gas emission limits, source testing frequency, CEMS, monitoring, recording, recordkeeping
Boilers ≤ 2 MMBtu/hr	Rules 1146.2 (natural gas only) (NOx) No requirements for boilers ≤ 2 MMBtu/hr using digester gas	Emission limitations for manufactured equipment fired with natural gas, monitoring, recording, recordkeeping
Emergency internal combustion engines	Rule 1470 – Requirements for Stationary Diesel-Fueled Internal Combustion Engines and Other Compression Ignition Engines (Diesel PM)	Operation limitations, emissions standards, fuel and fuel additive requirements, monitoring, recordkeeping, and reporting requirements
Non-emergency internal combustion engines	Rule 1110.2 (NOx, VOC, and CO)	Natural gas and digester gas emission limits, source testing frequency, source testing protocols, CEMS, monitoring, recording, recordkeeping, I&M plan requirements
Non-refinery flares	Rule 1118.1 (NOx, VOC)	Flare gas, including digester gas, emission limits, source testing requirements, monitoring, recording and recordkeeping
Miscellaneous combustion equipment	Rule 1147 (NOx)	Natural gas and digester gas emission limits, source testing requirements, monitoring, recording and recordkeeping
Turbines ≥ 0.3 MW	Currently no source specific rule for turbines ≥ 0.3 MW at POTWs	N/A
Turbines < 0.3 MW	Currently no source specific rule for turbines < 0.3 MW	N/A

AFFECTED FACILITIES AND EQUIPMENT

Based on South Coast AQMD's permit database, there are 30 POTW facilities with equipment subject to PR 1179.1. PR 1179.1 was developed to address digester gas fired combustion equipment located at POTWs that were not assessed in recently amended source-specific rules. Table 1-2 contains the equipment affected by PR 1179.1.

TABLE 1-2
AFFECTED EQUIPMENT

Equipment Type	Number of Units
Boilers > 2 MMBtu/hr	
Digester gas	7
Dual fuel	26
Boilers ≤ 2 MMBtu/hr	
Digester gas	6
Dual fuel	10
Turbines ≥ 0.3 MW	
Dual fuel	6
Turbines < 0.3 MW	
Digester gas	5
Dual fuel	5
Engines	
Dual fuel	21

Digester gas turbines and digester gas boilers were not assessed in the April 2019 amendments to Rule 1134 (turbines) or the December 2018 amendments to Rules 1146, 1146.2, and 1146.2 (boilers). Rule 1134 does not apply to any turbine located at a POTW and currently turbines located at POTWs are not subject to any rule. Provisions for turbines located at a POTW will be contained in PR 1179.1. All combustion equipment permitted to fire only non-digester gas fuels will remain subject to source-specific rules, with the exception of turbines greater than or equal to 0.3 MW. Equipment at POTWs not affected by PR 1179.1, include emergency engines, flares, miscellaneous equipment, and most natural gas fired equipment (excluding turbines ≥ 0.3 MW). Emergency engines are limited to 200 operating hours per year regardless of fuel. Flares located at POTWs were assessed as part of the January 4, 2019 amendments to Rule 1118.1 – Control of Emissions from Non-Refinery Flares (Rule 1118.1). Flares located at POTWs will remain subject to Rule 1118.1. One digester gas dryer was identified and is currently subject to Rule 1147 – NOx Reductions from Miscellaneous Sources (Rule 1147). Rule 1147 is scheduled to be amended after PR 1179.1 and will contain provisions for digester gas and natural gas fired miscellaneous equipment located at POTWs.

Applicability to Engines at POTWs

Initially during the rule development process, staff was proposing to keep engines subject to Rule 1110.2 since the November 2019 amendments confirmed no changes to the NOx, VOC, and CO limits established in the 2012 amendments. During the initial working group meetings, some stakeholders expressed their preference to include engines in PR 1179.1 in order to have one rule that would address all combustion equipment at POTWs. In subsequent working group meetings, staff informed stakeholders that permit revisions and updated Inspection and Monitoring (I&M)

plans would be needed to reflect PR 1179.1 provision references and presented the associated permit revision fees that facilities would incur.

The costs associated with engine permit revisions are higher compared to other combustion equipment because rule references are more detailed in engine permits and engine permits require Inspection and Maintenance (I&M) plans. Since facilities would incur additional permitting costs if engines requirements in Rule 1110.2 were to be moved to PR 1179.1, staff surveyed all the POTWs with engines to confirm if facilities support including engines in PR 1179.1, despite incurring associated fees.

Based on the survey, seven of the eight POTWs with non-emergency internal combustion engines support including biogas engines in Rule 1179.1 with the understanding of the additional permitting fees. As a result, staff proposes to include only biogas engines in the applicability of PR 1179.1 and natural gas engines will remain applicable to Rule 1110.2. Some stakeholders requested consideration of waiving these fees. However, permitting fees are established in Regulation ~~X~~III and the request would require a separate rule amendment.

PUBLIC PROCESS

The development of PR 1179.1 was conducted through a public process. Five Working Group meetings were held on: May 2, 2019, August 13, 2019, November 6, 2019, February 12, 2020, and June 4, 2020. Working Group meetings include representatives from affected agencies, environmental and community representatives, affected facilities, industry groups, and other interested parties. The purpose of the working group meetings is to discuss rule concepts and listen to public comments concerning the rule, with the objective to build consensus and address key issues.

A Public Workshop was held on July 22, 2020. The purpose of the Public Workshop is to present the proposed rule to the general public and to stakeholders.

Staff has also conducted multiple site visits as part of this rulemaking process and has met with individual facility operators. In addition, staff has met several times with the affected stakeholders via remote communication to review the proposed rule language and to address outstanding issues.

CHAPTER 2: BARCT ASSESSMENT

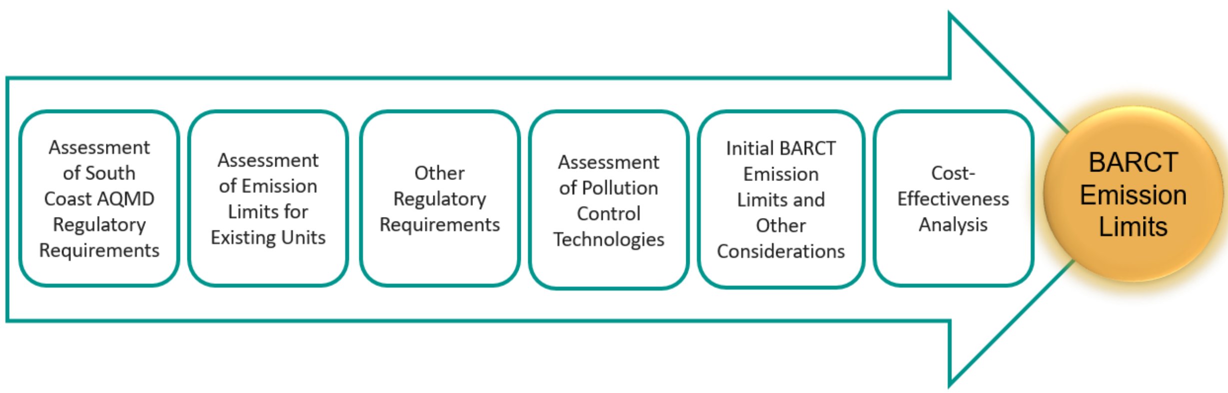
INTRODUCTION

The purpose of a Best Available Retrofit Control Technology (BARCT) assessment is to identify any potential emission reductions from specific equipment or industries and establish an emission limit that is consistent with state law. Under California Health and Safety Code § 40406, BARCT is defined 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."

BARCT assessments are performed periodically for equipment categories to determine if current emission limits are representative of BARCT emission limits. The BARCT assessment process identifies current regulatory requirements for equipment categories established by South Coast AQMD and other air districts. Permit limits and source test data are 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 the BARCT assessment. Costs are gathered and analyzed to determine the cost for a unit to meet the proposed initial NOx emission limit. A cost-effectiveness calculation is made that considers the cost to meet the initial proposed NOx limit and the reductions that would occur from implementing technology that could meet the proposed limit. A final BARCT emission limit is established that is based on the BARCT assessment, including the cost-effectiveness analysis.

Figure 2-1 – BARCT Assessment Process



BARCT assessments were conducted only for digester gas fired boilers and turbines as part of rulemaking for PR 1179.1 because digester gas engines underwent a BARCT analysis under Rule 1110.2 and most of those engines[1] had effective dates beginning in January 1, 2017. Therefore, a BARCT assessment for digester gas engines was not conducted for this rulemaking. Similarly, natural gas turbines underwent a BARCT analysis in 2019 and a BARCT assessment for those turbines was not conducted during this rulemaking.

[1] Variances were granted for three facilities that provided extra time to comply with the emission limits in Rule 1110.2 or implement an alternative digester gas beneficial use project.

BARCT ANALYSIS APPROACH

Boilers ≤ 2 MMBtu/hr

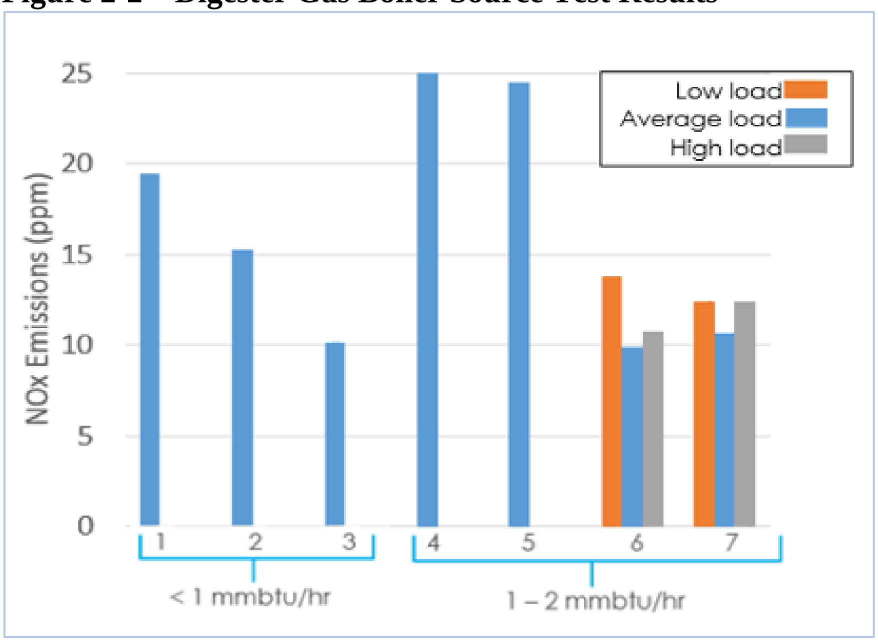
Assessment of South Coast AQMD Regulatory Requirements

There are 16 boilers ≤ 2 MMBtu/hr fired on digester gas within South Coast AQMD jurisdiction (6 digester gas, 10 dual fuel). The majority of these units are subject to individual permit limits. The permit limit for most of these units is 30 ppm at 3 percent oxygen on a dry basis with the exception of 2 boilers with a permit limit of 6 lbs/day and 2 boilers without a permit limit. South Coast AQMD has no rule requirement for boilers ≤ 2 MMBtu/hr that fire digester gas. Rule 1146.2 prohibits manufacturing for use or offering for sale for use burners ≤ 2 MMBtu/hr fired with natural gas that emit more than 30 ppm of NOx at 3 percent oxygen on a dry basis. Although natural gas units covered by Rule 1146.2 are exempt from permitting requirements, all digester gas units have South Coast AQMD permits.

Assessment of Emission Limits for Existing Equipment

Source tests were obtained for 7 of the 16 boilers and the results ranged from 10.2 ppm to 25.0 ppm at 3 percent oxygen on a dry basis. Units ≤ 1 MMBtu/hr all had source test results of less than 20 ppm at 3 percent oxygen on a dry basis. Figure 2-2 shows the source test results obtained for boilers ≤ 2 MMBtu/hr.

Figure 2-2 – Digester Gas Boiler Source Test Results



**All emission limits in parts per million (ppm) are referenced at 3 percent oxygen on a dry basis*

Other Regulatory Requirements

San Joaquin Valley Air Pollution Control District (SJVAPCD) and Sacramento Metropolitan Air Quality Management District (SMAQMD) have similar requirements that prohibit the distribution or installation of any burner not meeting the rule requirement; however, SJVAPCD and SMAQMD restrictions are not limited to natural gas only fired units. SJVAPCD's Rule 4308 limits NOx emissions from burners > 0.4 MMBtu/hr and less than 2.0 MMBtu/hr to 30 ppm at 3 percent oxygen on a dry basis, ≥ 0.075 and less than 0.4 MMBtu/hr to 77 ppm at 3 percent oxygen on a dry basis. SMAQMD's Rule 411 limits units > 1 MMBtu/hr and less than 5 MMBtu/hr to 30 ppm at 3 percent oxygen on a dry basis, and units 0.4 MMBtu/hr and ≤ 1 MMBtu/hr to 20 ppm at 3 percent oxygen on a dry basis.

Assessment of Pollution Control Technologies

Staff discussed with one supplier the availability of 12 ppm at 3 percent oxygen on a dry basis low NOx burners for boilers ≤ 2 MMBtu/hr. The supplier stated that 12 ppm at 3 percent oxygen on a dry basis burners are available in sizes ≥ 1 MMBtu/hr and that the 12 ppm NOx emission level can be guaranteed. Staff did not receive information from suppliers regarding achievable emission levels for boilers < 1 MMBtu/hr. A supplier informed staff that retrofitting low NOx burners for boilers < 1 MMBtu/hr could be challenging due to the limiting dimensions of a small boiler and could not guarantee 12 ppm at 3 percent oxygen on a dry basis for boilers < 1 MMBtu/hr. Source tests indicate that existing burners for boilers < 1 MMBtu/hr are meeting 20 ppm at 3 percent oxygen on a dry basis.

Initial BARCT Emission Limits and Other Considerations

Based on the information from one supplier and source test data, staff finds that a NOx emission limit of 12 ppm at 3 percent oxygen on a dry basis for boilers 1 – 2 MMBtu/hr and 20 ppm at 3 percent oxygen on a dry basis for boilers < 1 MMBtu/hr is feasible. The total emission reductions for boilers ≤ 2 MMBtu/hr would be 0.0005 tpd. Because of the small emission reductions combined with concerns expressed by facilities about meeting lower limits, staff is proposing a 30 ppm at 3 percent oxygen on a dry basis emission limit on all boilers ≤ 2 MMBtu/hr. All boilers ≤ 2 MMBtu/hr surveyed with the exception of four units described above are already permitted at 30 ppm at 3 percent oxygen on a dry basis.

TABLE 2-1
INITIAL NOX EMISSION LIMITS FOR DIGESTER GAS OR DUAL FUEL BOILERS ≤ 2 MMBTU/HR

Equipment Type	Limit at Rule Adoption
Boilers ≤ 2 MMBtu/hr firing digester gas, digester gas and another fuel, or other fuel	30 ppm*

**All emission limits in parts per million (ppm) are referenced at 3 percent oxygen on a dry basis.*

Cost-Effectiveness Analysis

For boilers currently permitted at 30 ppm at 3 percent oxygen on a dry basis, a cost-effectiveness analysis was not conducted for these units that will meet the proposed emission limit upon rule adoption. No costs were considered for boilers without a permitted NOx concentration limit to meet 30 ppm upon unit replacement, since replacing burner units is a normal part of business operations and would not incur additional costs.

BARCT Emission Limits

Staff proposes that units without permitted NOx concentration limits will be subject to the emission limit upon a burner or boiler replacement. The following table provides the proposed BARCT emission limits for boilers ≤ 2 MMBtu/hr.

TABLE 2-2
PROPOSED BARCT EMISSION LIMITS FOR DIGESTER GAS OR DUAL FUEL BOILERS ≤ 2 MMBTU/HR

Equipment Type	Limit at Rule Adoption*	Limit Upon Burner or Boiler Replacement*
Boilers ≤ 2 MMBtu/hr firing digester gas, digester gas and another fuel, or other fuel	Permit Limit	30 ppm

**All emission limits in parts per million (ppm) are referenced at 3 percent oxygen on a dry basis.*

Boilers > 2 MMBtu/hr

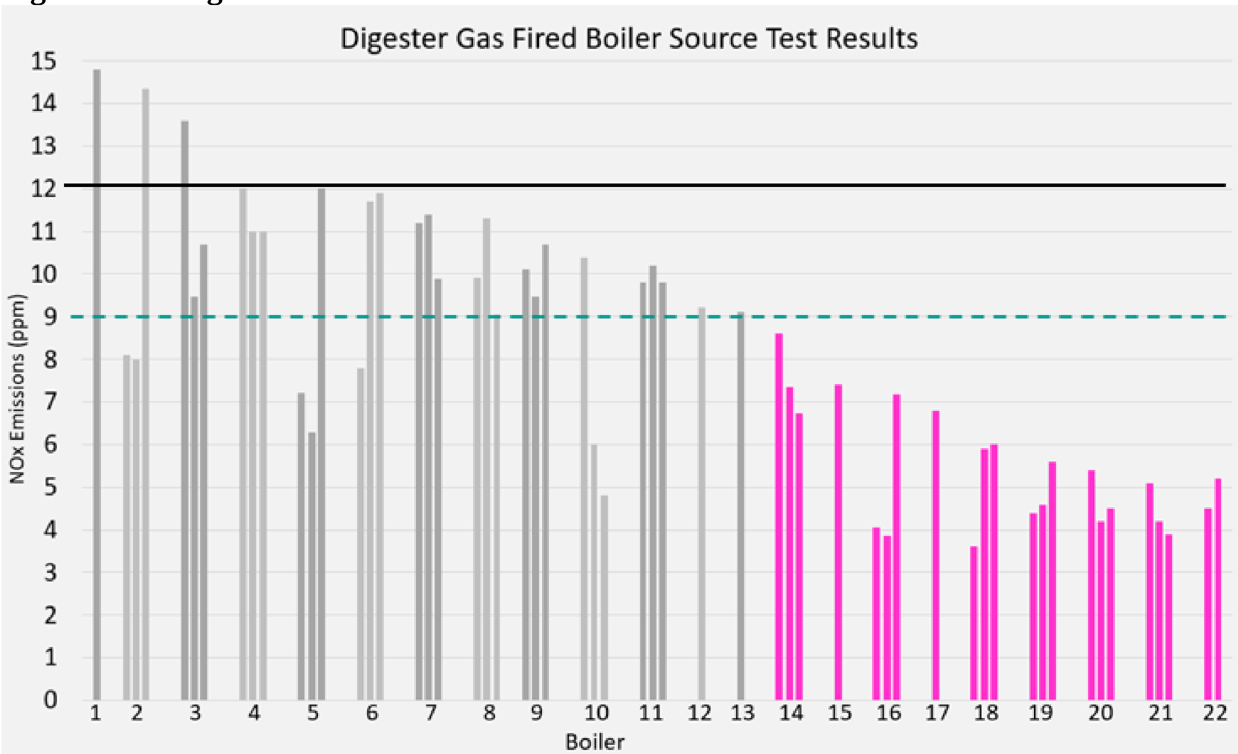
Assessment of South Coast AQMD Regulatory Requirements

South Coast AQMD’s Rules 1146 and 1146.1 require boilers > 2 MMBtu/hr meet 15 ppm at 3 percent oxygen on a dry basis when firing digester gas and 9 ppm at 3 percent oxygen on a dry basis when firing natural gas. Rules 1146 and 1146.1 were recently amended in December 2018 and a BARCT assessment was conducted for natural gas boilers. The amendments require certain natural gas boilers to meet 7 ppm at 3 percent oxygen on a dry basis, however, natural gas boilers located at municipal sanitation service facilities are subject to 9 ppm at 3 percent oxygen on a dry basis. Co-fired boilers remained subject to a weighted average emission limit when firing more than an approved percentage of natural gas.

Assessment of Emission Limits for Existing Units

Source test results for boilers >2 MMBtu/hr in South Coast AQMD jurisdiction firing 100 percent digester gas indicate that 9 ppm at 3 percent oxygen on a dry basis is achievable. Source tests were obtained for 22 out of 33 boilers permitted to fire digester gas. Twenty-six boilers are dual fuel and have the ability to separately fire digester gas and natural gas, and 7 are digester gas fired only. Source tests contained results for boilers firing low, mid, and high loads with the exception of 5 boilers firing mid load and one boiler firing low and average loads. All boilers in Figure 2-3 meet the 15 ppm at 3 percent oxygen on a dry basis emission limit. Nine boilers source tested below 9 ppm at 3 percent oxygen on a dry basis at all loads (highlighted). Results are displayed in order of low, mid, and high load in Figure 2-3.

Figure 2-3 – Digester Gas Fired Boiler Source Test Results



**All emission results in parts per million (ppm) are referenced at 3 percent oxygen, on a dry basis.*

Periodic monitoring is required by Rules 1146 and 1146.1. Periodic monitoring results were also analyzed to determine if source tests are representative of normal boiler performance. Complete sets of monthly monitoring data were obtained for six boilers. Staff determined that source results were representative of average emission levels. For example, two boilers that source tested below 9 ppm at 3 percent oxygen on a dry basis had periodic monitoring test results below 9 ppm at 3 percent oxygen on a dry basis in more than 90 percent of the tests. One boiler exceeded 9 ppm at 3 percent oxygen on a dry basis twice over the course of five years. Another boiler exceeded 9 ppm at 3 percent oxygen on a dry basis three times in five years.

Other Regulatory Requirements

Two districts have emission limits more stringent than South Coast AQMD for digester gas boilers. SJVAPCD currently has a permitted boiler that fires digester gas. The boiler complies with SJVAPCD's Rule 4320 limit of 9 ppm at 3 percent oxygen on a dry basis. The boiler is a dual fuel and 16.7 MMBtu/hr. The boiler recently source tested at 7.9 ppm at 3 percent oxygen on a dry basis while firing 100 percent digester gas. Stakeholders commented that SJVAPD's allowed tuning practices prior to source testing may allow for lower emission results and/or rule limits. South Coast AQMD requires that a boiler must operate at least 250 hours or 30 days subsequent to tuning or servicing. Staff at SJVAPCD informed South Coast AQMD that a boiler must be operating at least 2 hours subsequent to tuning. Staff was unable to locate a protocol that specifies the requirements for source testing. Nevertheless, even with different source test protocols, results for digester gas fired boilers using South Coast AQMD protocols confirm BARCT at NOx emissions levels < 9 ppm at 3 percent oxygen on a dry basis.

SMAQMD's Rule 411 requires that boilers > 20 MMBtu/hr meet 9 ppm at 3 percent oxygen on a dry basis, boilers ≥ 5-20 MMBtu/hr meet 15 ppm at 3 percent oxygen on a dry basis, and boilers ≥ 1 – 5 meet 30 ppm at 3 percent oxygen on a dry basis. The limits apply to boilers that fire any fuel which is a gas at standard conditions. Rule 411 does not specify a limit for digester gas. Units ≥ 5 MMBtu/hr that fire landfill gas have a limit of 15 ppm at 3 percent oxygen on a dry basis. SJVAPCD's Rule 4320 specifies limits for boilers ≥ 2 – 5 MMBtu/hr that fire gaseous fuel, where "gaseous fuel" is defined as any fuel that is a fuel at which is a gas at standard conditions. The limits are 12 ppm (atmospheric) and 9 ppm (non-atmospheric), at 3 percent oxygen on a dry basis. Boilers > 5 MMBtu/hr that fire more than 50 percent by volume PUC quality gas are subject to an emission limit of 9 ppm at 3 percent oxygen on a dry basis.

Assessment of Pollution Control Technologies

Thermal NOx is the largest contributor to NOx emissions from boilers and is formed by high flame temperatures. Different control technologies exist that reduce NOx emissions from boilers. Low NOx burners and flue gas recirculation reduce the formation of thermal NOx at the combustion zone and SCR removes NOx post-combustion. Low NOx burners control the air-fuel mixture during combustion and modify the shape of the flame or number of flames to reduce NOx formation and maintain efficiency. Flue gas recirculation is a method of NOx control that returns hot flue gas to the combustion air stream to lower flame temperature. Low NOx burners are currently used on all boilers that fire digester gas in South Coast AQMD. Some boilers utilize flue gas recirculation systems alone or with an oxygen trim system. SCR is not necessary to meet the current limit of 15 ppm and no facilities are using SCR to limit NOx emissions on boilers.

One stakeholder commented that their boilers experience flame-out due to siloxane build up. This facility has opted to treat the gas prior to combustion to resolve the issue. Stakeholders also commented on the instability of NOx emission levels while firing digester gas with low-NOx burners. One facility commented that holes are created in their mesh burner screens, possibly due to digester gas combustion hot spots.

Staff discussed the issues brought forth by stakeholders with three burner suppliers. Suppliers stated that unstable NOx emissions can result from fluctuations in the higher heating value (HHV) of the digester gas, weather changes, load changes, and contaminants.

Staff was informed that oxygen trim systems are beneficial in managing fluctuations in HHV and can tolerate fluctuations of ±100 Btu/scf. Fluctuations of ±50 Btu/scf in HHV should not cause unstable NOx emissions. Changes in weather such as temperature swings and humidity swings can lead to emissions instability and would require more frequent tuning. Weather changes can result in 3 ppm – 4 ppm, at 3 percent oxygen on a dry basis swings in NOx emissions and the recommended tuning frequency is every 3 – 6 six months depending on the target NOx emission levels. Load swings are managed with the turndown ratio of the burner. A typical low NOx burner has a turndown ratio of 4:1. A burner with a small turndown ratio offers less flexibility to manage load swings.

Contaminants can damage burner screens that may result in unstable NOx emissions. Corrosive contaminants such as H_2S can affect screens and siloxanes can clog screens leading to hotspots that may cause holes to form in the screen. If gas is untreated prior to combustion, burners need to be cleaned every 3 – 6 months depending on the level of contaminants. To avoid damage to burner screens, gas should be adequately treated to remove contaminants prior to combustion. Ambient temperature is another factor that may contribute to holes forming in burner screens as holes may form from air expansion. Oxygen trim systems can be used to manage the amount of air in the fuel to avoid complications with air expansion. Woven screens are another option for managing fluctuations in air volume.

One supplier stated that achieving emission levels of 7 ppm – 9 ppm, at 3 percent oxygen on a dry basis is possible with proper tuning and possibly an oxygen trim system or flue gas recirculation system that optimizes the air-to-fuel ratio. However, this supplier could not guarantee emission levels at 9 ppm at 3 percent oxygen on a dry basis due to the varying HHV in digester gas.

Initial BARCT Emission Limits and Other Considerations
Staff proposed a NOx emission limit of 12 ppm at 3 percent oxygen on a dry basis for boilers greater than 2 MMBtu/hr. Earlier in the rule development process, staff proposed an initial NOx emission limit of 9 ppm at 3 percent oxygen on a dry basis based on discussions with suppliers and emission test results. Staff reached out to stakeholders and followed up with suppliers regarding the proposed NOx emission limit. Stakeholders expressed their concern about meeting 9 ppm at 3 percent oxygen on a dry basis consistently and stated that 9 ppm at 3 percent oxygen on a dry basis is achievable, but it would require operators to tune the boiler more frequently, impacting resources at the facilities.

Two other suppliers guaranteed NOx emission levels of <12 ppm at 3 percent oxygen on a dry basis for burner replacements. One of the suppliers stated that 9 ppm at 3 percent oxygen on a dry basis burners would be available in the next few years. Stakeholders expressed their reluctance to rely on supplier guarantees. However, in staff's analysis of source test results for boilers > 2 MMBtu/hr, 19 out of 22 boilers (Figure 2-3) met 12 ppm at 3 percent oxygen on a dry basis for all loads required by the source tests. Staff examined the performance of the burners manufactured by the suppliers that guaranteed 12 ppm at 3 percent oxygen on a dry basis. The source test results showed that these specific burners met 12 ppm. Staff concluded that burners that cannot not meet 12 ppm could meet the proposed emission limit if replaced with burners that are shown and guaranteed to meet 12 ppm at 3 percent oxygen on a dry basis.~~The suppliers claiming a guarantee of 12 ppm at 3 percent oxygen on a dry basis do not manufacture the burners that source tested above 12 ppm at 3 percent oxygen on a dry basis.~~ Based on the information from emission tests results and the emission levels that suppliers will guarantee for new burners, staff proposed an emission limit of 12 ppm at 3 percent oxygen on a dry basis.

Cost-Effectiveness Analysis
Staff conducted a cost-effectiveness analysis to retrofit boilers with burners that can meet 12 ppm at 3 percent oxygen on a dry basis. The average cost-effectiveness to meet 12 ppm at 3 percent oxygen on a dry basis is > $50,000 per ton of NOx reduced when achieved by requiring facilities

to replace burners before the time that the facility would regularly replace the equipment because emission reductions are relatively low.

BARCT Emission Limits

Staff is proposing the current NOx emission limit of 15 ppm at 3 percent oxygen on a dry basis for boilers < 2 MMBtu/hr. Replacements and new units will be required to meet BACT emission levels. The following table provides the proposed BARCT emission limits for boilers > 2 MMBtu/hr.

TABLE 2-~~3~~4
PROPOSED BARCT EMISSION LIMITS FOR BOILERS > 2 MMBTU/HR

Equipment Type	Limit at Rule Adoption*	Limit Upon Burner or Boiler Replacement
Boilers > 2 MMBtu/hr firing at least 90% firing digester gas	15 ppm	BACT Emission Level

**All emission limits in parts per million (ppm) are referenced at 3 percent oxygen on a dry basis.*

Turbines < 0.3 MW

There are 10 turbines < 0.3 MW located at two POTW facilities within South Coast AQMD jurisdiction. Five are exempt from permitting and do not have emission limits. The other five are not yet commissioned and have been permitted at 9 ppm at 15 percent oxygen on a dry basis.

Assessment of South Coast AQMD Regulatory Requirements

There is currently no South Coast AQMD rule that establishes a NOx limit for turbines < 0.3 MW ~~at South Coast AQMD~~. Rule 219 allows microturbines, defined as ≤ 3.5 MMBtu/hr (total output < 2 MW) and certified at the time of manufacturer with the State of California or in operation prior to May 3, 2013, to be exempt from permitting provided that a filing pursuant to Rule 222 is submitted~~ and the microturbines were in operation prior to May 3, 2013 or the microturbines were certified by the state of California at the time of manufacture~~. A turbine < 0.3 MW could be considered a microturbine, provided it was certified at the time of manufacturer with the State of California or in operation prior to May 3, 2013. Staff is amending Rule 1147 – NOx Reductions from Miscellaneous Sources that will establish provisions for natural gas fired turbines < 0.3 MW~~microturbines~~ in addition to this proposed rule.

Assessment of Emission Limits for Existing Units

The five turbines currently operating are not subject to an~~s~~ emission limit. One source test was obtained for one turbine. The turbine source tested at 1.25 ppm at 15 percent oxygen on a dry basis with 100 percent digester gas.

Other Regulatory Requirements

Staff did not identify NOx emission limits for turbines < 0.3 MW in another air district's rules. The State of California has issued requirements for ~~micro~~turbines, including turbines < 0.3 MW, that are exempt from any District requirements. Such ~~micro~~turbines must comply with CARB's Distributed Generation regulations standards, which are near 2 ppm at 15 percent oxygen on a dry basis or NOx (0.07 lbs/MW-hr), and must be certified, if manufactured after January 1, 2013. However, existing unpermitted units are certified and subject to previous CARB Executive Orders of 9 ppm at 15 percent oxygen on a dry basis NOx after January 1, 2008 and before January 1, 2013 (date of manufacture).

Assessment of Pollution Control Technologies

Turbines < 0.3 MW~~Microturbines~~ use a lean pre-mix to limit NOx emissions without post combustion control technology such as SCR. SCR is not suitable for these ~~micro~~turbines because of the low exhaust temperature and SCR's requirement for high exhaust temperature to activate catalysts. One ~~microturbine~~ supplier guarantees 9 ppm at 15 percent oxygen on a dry basis for their ~~micro~~turbines < 0.3 MW that fire digester gas or a blend of digester gas and natural gas. The supplier stated that 9 ppm at 15 percent oxygen on a dry basis can be met over a range of loads, but high load is suggested to consistently meet emission levels. Proper gas treatment and maintenance is imperative to meet the target emission levels.

Initial BARCT Emission Limits and Other Considerations

Staff is proposing a NOx emission limit of 9 ppm at 15 percent oxygen on a dry basis based on supplier discussions and current permitted levels for all turbines < 0.3 MW with the exception of turbines that are permit exempt and were in operation prior to May 3, 2013. There is insufficient source test information to determine if the existing turbines that are permit exempt can meet 9 ppm at 15 percent oxygen on a dry basis.

TABLE 2-4~~5~~
INITIAL NOX EMISSION LIMITS FOR DIGESTER GAS OR DUAL FUEL TURBINES < 0.3 MW

Equipment Type	Limit at Rule Adoption*
Turbines < 0.3 MW in operation prior to May 3, 2013 firing digester gas, digester gas and natural gas, or natural gas	N/A
Turbines < 0.3 MW firing digester gas, digester gas and another fuel, or other fuel	9 ppm

**All emission limits in parts per million (ppm) are referenced at 15 percent oxygen on a dry basis.*

Cost-Effectiveness Analysis

Five of the 10 existing turbines < 0.3 MW are permitted at the proposed initial NOx limit and no cost-effectiveness analysis was conducted. The other five turbines will not be affected by the proposed emission limit until unit replacement. No incremental costs are assumed to replace units with units that can meet 9 ppm at 15 percent oxygen on a dry basis. A cost-effectiveness analysis was not conducted for units that will meet the emission limit upon replacement.

BARCT Emission Limits

The following table provides the proposed BARCT emission limits for turbines < 0.3 MW that fire digester gas or a digester gas and another fuel~~blend~~.

TABLE 2-5~~6~~
PROPOSED BARCT EMISSION LIMITS FOR DIGESTER GAS OR DUAL FUEL TURBINES < 0.3 MW

Equipment Type	Limit at Rule Adoption*	Limit Upon Turbine Replacement*
Turbines < 0.3 MW in operation prior to May 3, 2013 firing digester gas, digester gas and natural gas, or natural gas	N/A	N/A
Turbines < 0.3 MW firing digester gas, digester gas and another fuel, or other fuel	9 ppm	9 ppm

**All emission limits in parts per million (ppm) are referenced at 15 percent oxygen on a dry basis.*

Turbines ≥ 0.3 MW
Based on the South Coast AQMD's permit database, there are six combined cycle turbines located at two POTWs that fire either digester gas only or a digester gas blend. One facility has three 11.35 MW turbines that fire a blend of digester gas and natural gas (60 percent digester gas, 40 percent natural gas). These turbines currently use SCR and the digester gas is treated to remove siloxanes prior to combustion. The other facility has three 9.9 MW turbines that fire digester gas but are permitted to blend up to 40 percent natural gas. This facility does not have SCR and has a less aggressive~~does not treat the~~ digester gas treatment process~~prior to combustion~~.

Assessment of South Coast AQMD Regulatory Requirements
South Coast AQMD has no rule for turbines located at a POTW. South Coast AQMD Rule 1134 which applies to stationary gas turbines, 0.3 MW and larger, excludes turbines located at POTW facilities.

Assessment of Emission Limits for Existing Units
The turbines are subject to South Coast AQMD permit limits. The turbines have NOx concentration limits of 18.8 ppm and 25 ppm, at 15 percent oxygen on a dry basis. Table 2-6~~VIII~~ summarizes the unit sizes, type of emission controls, and permitted NOx concentration limit, at each facility.

TABLE 2-6~~7~~
CURRENT PERMIT LIMITS FOR DIGESTER GAS TURBINES

Facility	Number of Units	Unit Size (MW)	Emission Controls	Permit Limit (ppmv at 15% O2)
1	3	9.9	Water injection only	25
2	3	11.35	SCR	18.8

**All emission limits in parts per million (ppm) are referenced at 15 percent oxygen on a dry basis.*

Staff analyzed recent source test results available for the turbines. Two of the three turbines permitted at 18.8 ppm source tested at 14.7 ppm and 15.9 ppm, at 15 percent oxygen on a dry basis, when firing digester gas and 13 ppm and 14.3 ppm, at 15 percent oxygen on a dry basis, when firing a 60/40 blend of digester gas/natural gas. Source test results for the third turbine were unavailable. The three turbines permitted at 25 ppm source tested between 20.7 ppm – 21.3 ppm, at 15 percent oxygen on a dry basis.

SJVAPCD has permitted two turbines located at a POTW that fired a blend of digester gas (~70 percent) and natural gas (~30 percent) at 5 ppm at 15 percent oxygen on a dry basis. The operator of the facility informed staff that the facility was using water injection to meet a previous 25 ppm at 15 percent oxygen on a dry basis NOx rule limit. The facility discontinued water injection and implemented gas treatment and SCR to meet the new 5 ppm at 15 percent oxygen on a dry basis rule limit. Source test results were obtained prior to the decommissioning of the turbines. Seven source tests from the last five years of operation were obtained for the turbines. The results ranged from 2.5 ppm – 3.9 ppm, at 15 percent oxygen on a dry basis. The turbines were in operation from 2004 – 2016.

Other Regulatory Requirements
Staff identified NOx emission limits for digester gas turbines in other air districts' rules. Requirements at SMAQMD and SJVAPCD for digester gas turbines are as stringent or more stringent than South Coast AQMD's permit limits.

SJVAPCD's Rule 4703 requires combined cycle turbines > 10 MW to meet a NOx limit of 3 ppm or 5 ppm, at 15 percent oxygen on a dry basis, depending on the implementation schedule. The emission limits apply to turbines using gas fuel that includes digester gas. Units meeting 3 ppm at 15 percent oxygen on a dry basis had a longer compliance timeframe. Turbines between 3 MW – 10 MW that operate 877 hours per year or more are subject to a NOx concentration limit of 5 ppm at 15 percent oxygen on a dry basis.

SMAQMD's Rule 413 requires turbines ≥ 10 MW with SCR that operate 877 hours per year or more to meet 9 ppm at 15% oxygen on a dry basis for turbines that use gaseous fuel that includes any fuel that is a gas at standard conditions. Turbines ≥ 2.9 – < 10 MW are subject to a 25 ppm at 15 percent oxygen on a dry basis NOx concentration limit. Four turbines are permitted by SMAQMD that fire a blend of digester gas and natural gas and are permitted at 2.5 ppm and 2.0 ppm, at 15% oxygen on a dry basis. However, these turbines used a blend of only 2 percent digester gas. SCR is used for NOx control on the turbines permitted at 2.5 ppm and SCR along with a dry low NOx combustion system is used for the turbines permitted at 2.0 ppm. Staff concluded that the turbines permitted by SMAQMD do not provide a comparison to the turbines in South Coast AQMD for achievable NOx emission levels from digester gas turbines because a) the dry low NOx combustion systems used to meet 2 ppm are not compatible with ~~turbines that use~~ fuel blends with a lower Wobbe index (not to pipeline quality gas specifications), for some turbines; and, b) the percentage of digester gas in the fuel blend is much lower than the percentages used in the fuel for the turbines at South Coast AQMD.

Assessment of Pollution Control Technologies
Staff assessed the feasibility of certain control technologies to meet specific NOx emission levels. Implemented control technologies were evaluated by performance data and discussions with

facility operators and equipment suppliers. Staff visited POTW sites to learn from equipment operators about their experiences with combustion and control equipment.

Water or Steam Injection

Water or steam injection is a common control system built into turbines that reduces thermal NOx formation by lowering the combustion zone temperature. Water injection requires demineralized water that is more costly and less convenient than utility water. Storage sites and delivery are required for use of demineralized water. Utilizing water injection can be undesirable due to the potential for imprecise water application that can lead to hotspots, causing NOx formation, increased fuel usage and increased carbon monoxide (CO) emissions, along with the deterioration of turbine parts from water abrasion. The facility with turbines permitted at 25 ppm at 15 percent oxygen on a dry basis informed staff that their turbines can meet 18.8 ppm at 15 percent oxygen on a dry basis with increased water injection.

Dry Low Emissions (DLE)

Dry low emission (DLE) or lean pre-mixed technology is a combustion system that does not use water or steam to reduce thermal NOx. DLE systems have a mechanism to pre-mix the air and fuel to create a lean mixture that allows combustion at a lower temperature. Lean pre-mixed combustion systems minimize local hotspots that produce elevated combustion temperatures, forming thermal NOx. One turbine supplier informed staff that its DLE systems are not compatible with digester gas due to the low Wobbe index of digester gas. The DLE system for this particular turbine is limited to fuels with a Wobbe index number range of 1100-1340, whereas the Wobbe index range of digester gas is much lower, at approximately 600. Although increasing the amount of natural gas in the fuel blend would increase the Wobbe index number, a 60/40 blend of digester gas/natural gas would not be compatible with the dry low NOx combustion system. Furthermore, DLE combustion systems are an intrinsic part of a turbine's design and not considered available for retrofit on existing turbines.

Selective Catalytic Reduction (SCR)

SCR is a primary post-combustion technology for NOx reduction and is capable of reducing 90-95 percent of post combustion NOx. SCR reduces NOx to nitrogen and water through a reaction with ammonia and oxygen. Catalyst is used for the reaction and is negatively affected by siloxane contamination in biogas. Siloxane containing biogas requires gas treatment to maintain SCR effectiveness. SCR is a post-combustion NOx control technology and may be used in combination with combustion alteration NOx control technologies, such as dry low NOx combustion systems and low NOx burners. SCR requires on-site storage of ammonia or urea and the technology carries the potential of creating unwanted stack ammonia emissions (ammonia slip) from unreacted ammonia. Catalysts are available that reduce ammonia slip emissions but were not evaluated as part of the SCR technology assessment. A limiting factor for SCR applications is the technology's requirement for high operating temperature. Exhaust gas temperatures typically need to be between 400F – 800F. SCR is not suitable for combustion equipment with low exhaust temperatures. SCR is used on a variety of equipment including turbines, engines, and boilers, but must be accompanied with an adequate fuel gas treatment system (FGTS). One equipment supplier stated that siloxane levels need to be as low as 25 ppb to guarantee SCR performance for any length of time. The gas treatment systems currently used at POTWs and landfills have been designed to remove siloxanes to levels between 75 ppb – 500 ppb. Despite this, these gas treatment systems are currently used in conjunction with SCR. Removal of siloxanes prior to combustion is necessary for proper SCR performance. Inadequate siloxane removal can quickly deactivate the SCR catalyst and require more frequent catalyst replacements.

Within South Coast AQMD, SCR is currently used at a POTW with three digester gas turbines equipped with SCR, which were permitted in 2017. Those turbine's uncontrolled NOx emissions of 213 ppm at 15 percent oxygen on a dry basis can be reduced to 18.75 ppm at 15 percent oxygen on a dry basis with SCR and the SCR could provide 91.2 percent NOx reduction. The use of SCR at this facility requires a FGTS to remove siloxanes and H_2S contaminants that the facility implemented with the project. Two turbines have source tested at 15.9 ppm and 14.7 ppm, at 15 percent oxygen on a dry basis, when firing 100 percent digester gas. A source result for the third turbine was unavailable. It is expected that turbines equipped with SCR firing digester gas can achieve reductions consistent with the reductions that this POTW is achieving with SCR on the turbines.

SCR was also used at a POTW within SJVAPCD. SCR was used on two turbines that had inlet NOx emission levels of 25 ppm at 15 percent oxygen on a dry basis at minimum. The turbines source tested as low as 2.5 ppm at 15 percent oxygen on a dry basis, indicating that the SCRs were capable of achieving 90 percent NOx reduction when operated with digester gas turbines.

Fuel Gas Treatment Systems

FGTS remove undesired compounds from non-conventional fuels, such as digester gas. Digester gas produced at wastewater treatment plants contain siloxane and H_2S contaminants. It is imperative that digester gas is treated for proper combustion and post-combustion equipment function. While some equipment is less impaired by siloxanes and other contaminants, some level of gas treatment is usually required for a combustion process that uses digester gas. There are three prominent FGTS types that utilize different techniques for removing contaminants – consumable media type, regenerative media type and a chiller/adsorption type. A FGTS may consists of one or a more removal system types.

The effectiveness of contaminant adsorption depends on the media type and the contaminants in the gas stream. The three most common types of media that are used in the South Coast AQMD at landfills and POTWs are activated carbon, molecular sieve, and silica gel. Each media type has its advantages. Activated carbon is a versatile adsorbent that is highly porous and is suitable to adsorb organic molecules. A molecular sieve has pores of uniform size and is capable of performing selective removal of contaminants at low concentrations. Silica gel is a shapeless and porous adsorbent that has a greater capacity than activated carbon to adsorb siloxanes and has a high affinity for water that aids in moisture removal.

Consumable media type systems are commonly used with activated carbon. This type of removal system requires saturated media to be changed out. Spent media is disposed and new media is reintroduced. Installment and maintenance costs are typically less than regenerative and chiller media systems because the equipment is less complex than consumable media systems, but more frequent media removal and disposal can result in significant operating costs to the facility.

Regenerative media systems are commonly used with media such as molecular sieve, silica gel, clay and zeolite. These systems consist of at least two media canisters. One batch of media processes gas while the other regenerates by purging with hot air. Regenerative media types require smaller canisters and less media in comparison to consumable media systems. Regenerative media function can be enhanced by applying polymeric resins. Polymeric~~s~~ resins can increase service life, increase adsorbent capacity, and remove contaminants quicker and at a lower temperature when regenerating.
Chiller/adsorption or refrigeration systems remove contaminants by reducing the temperature of the digester gas to condense out moisture and contaminants. These systems have been used in combination with consumable media systems at landfills. The consumable media system serves as a polishing stage to remove trace amounts of siloxanes or other contaminants. Wastewater treatment and landfill facilities have reported 50 percent removal efficiency of siloxanes and 32 percent long-term removal efficiency of siloxanes, with refrigeration. Bench-scale studies have shown 95 percent removal of siloxanes with advanced refrigeration.[1]

Within South Coast AQMD, five POTW facilities use FGTS systems and treat gas prior to combustion in twelve digester gas engines that are equipped with SCR for post-combustion control. One facility uses a FGTS prior to combustion in three turbines. At other POTWs, FGTS systems are also used to treat digester gas prior to entering a fuel cell. If low siloxane levels are not maintained, media replacement will be more frequent, raising operating costs associated with fuel gas treatment systems.

New Turbines

Newer gas turbines are capable of low NOx emission levels, between 4 ppm – 25 ppm when firing natural gas without SCR. Achievable NOx emission levels while firing digester gas vary and depend on the constituents of the digester gas. DLE systems, in some turbines, are incompatible with digester gas due to the low Wobbe index number for digester gas.~~, but t~~There is one commercially available turbine ≥ 0.3 MW that incorporates a DLE system compatible with biogas and a recuperator. The manufacturer of this turbine guarantees 15 ppm at 15 percent oxygen on a dry basis for landfill gas and 25 ppm at 15 percent oxygen on a dry basis for digester gas. The widespread application of this turbine is limited due to its maximum output rating of 4.6 MW and low exhaust temperature, making it unsuitable for high pressure heat recovery steam generation.

Two other turbine manufacturers have estimated emission levels of 15 ppm and 25 ppm when firing digester gas for larger sized turbines, in the 10 MW range. One of the turbine suppliers stated that they can guarantee emissions levels of 15 ppm and 25 ppm, at 15 percent oxygen on a dry basis, depending on the model, for turbines without SCR fueled with digester gas.

Within landfills and POTWs in California, eleven turbines operate without SCR and are fueled with either landfill gas or digester gas. These are the only known turbines in operation within California with a DLE system that is~~are~~ compatible with biogas. Ten of these turbines are located at landfills and one is located at a POTW. Digester gas is treated ~~is~~ prior to combustion in the

[1] Jeffrey Pierce & Ed Wheless. "Siloxanes in Landfill and Digester Gas Update", *27th Annual SWANA LFG Symposium*, March 2004.

turbines and SCR is not utilized. All turbines located at the landfills source tested between 3.1 ppm – 7.6 ppm, at 15 percent oxygen on a dry basis. Some of the turbines are permitted at 12.5 ppm at 15 percent oxygen on a dry basis, while others are permitted at 25 ppm at 15 percent oxygen on a dry basis.

Staff obtained additional information from a POTW that operates an identical turbine to the turbines operated at landfills not using SCR. The turbine located at the POTW achieved NOx emission levels consistent with the landfill turbines. The operator of the POTW facility provided monthly emission tests results for years 2018 and 2019. Results ranged from 3.7 ppm – 8.1 ppm, at 15 percent oxygen on a dry basis (2018) and 4.4 ppm – 7.7 ppm, at 15 percent oxygen on a dry basis (2019). The operator informed staff that typical emission levels for the turbine range between 4 ppm – 6 ppm, at 15 percent oxygen on a dry basis.

Initial BARCT NOx Emission Limits and Other Considerations

Staff proposed initial NOx emission limits of 18.8 ppm, 12.5 ppm, and 5 ppm, at 15 percent oxygen on a dry basis. The proposed NOx emission limit of 18.8 ppm at 15 percent oxygen on a dry basis is based on the facility's claim that they can meet 18.8 ppm at 15 percent oxygen on a dry basis with increased water injection. The proposed NOx emission limit of 12.5 ppm is based on the lowest permitted limit for biogas fired turbines without SCR. The proposed NOx emission limit of 5 ppm at 15 percent oxygen on a dry basis emission limit is based on the achievable emission level with SCR.

Earlier in the rule development, staff proposed an emission limit of 2.5 ppm at 15 percent oxygen on a dry basis for turbines not equipped with SCR. The proposed NOx emission limit was based on SCR's ability to reduce NOx by 90 percent. Ninety percent removal efficiency was determined by actual operations at two POTWs and supported by three suppliers. Staff determined that new turbines with uncontrolled emission levels of 25 ppm at 15 percent oxygen on a dry basis equipped with SCR with 90 percent NOx removal efficiency can meet 2.5 ppm at 15 percent oxygen on a dry basis. Stakeholders commented that an emission limit of 2.5 ppm at 15 percent oxygen on a dry basis would result in the shutdown of existing beneficial use projects and deter facilities from implementing new beneficial use projects. Stakeholders also stated that gas treatment technology is not reliable due to the uncertainties involved with biogas contaminants and that meeting an emission limit of 2.5 ppm at 15 percent oxygen on a dry basis consistently has the potential to be extremely difficult to achieve or maintain.

Staff acknowledges that biogas content is unique to each facility and that gas treatment systems may need to be specifically designed to treat a facility's digester gas. However, many POTW facilities across the United States currently rely on gas treatment systems for combustion and post-combustion control operation. Within South Coast AQMD, five facilities use digester gas treatment with 12 engines with SCR and one POTW uses gas treatment with three turbines with SCR. Staff's assessment of current technology and applications suggest that gas treatment, along with SCR can reduce NOx emissions from combustion equipment. However, requiring an emission limit of 2.5 ppm at 15 percent oxygen on a dry basis on a turbine with uncontrolled emissions of 25 ppm at 15 percent oxygen on a dry basis requires the SCR to perform with 90 percent efficiency. Although staff's technology assessment for SCR determined that SCR can remove NOx with 90 percent efficiency, staff increased the emission limit of 2.5 ppm to 5 ppm, at 15 percent oxygen on a dry basis, to allow a compliance margin for digester gas turbines. A new turbine with uncontrolled emission levels of 15 ppm at 15 percent oxygen on a dry basis would require the SCR to function at 67 percent efficiency and a new turbine with uncontrolled emissions of 25 ppm at 15 percent oxygen on a dry basis would require the SCR to function at 80 percent efficiency.

Staff also proposed an initial NOx emission limit for turbines without SCR to allow facilities an alternative to using SCR on digester gas fired turbines. Staff proposed an initial NOx emission limit of 12.5 ppm at 15 percent oxygen on a dry basis based on permitted limits and emissions analyses for biogas turbines without SCR.

Stakeholders expressed their concern about using a landfill turbine's performance as a comparison for a turbine's performance at a POTW. Staff followed up with the manufacturer of the turbine that achieves emission levels below 12.5 ppm, shown with source tests and CEMS data, to discuss the turbine's ability to meet a NOx emission limit of 12.5 ppm at 15 percent oxygen on a dry basis. The supplier stated that a 12.5 ppm NOx emission level could not be guaranteed for digester gas. The guaranteed emission level for this turbine is 25 ppm at 15 percent oxygen on a dry basis. The supplier also informed staff that the POTW operating their turbine had emission levels higher than 12.5 ppm at 15 percent oxygen on a dry basis in its first year of operation. Given the additional information on this turbine type, staff is not proposing a separate emission level for turbines without SCR.

TABLE 2-7~~8~~
INITIAL NOX EMISSION LIMITS FOR DIGESTER GAS AND DUAL FUEL TURBINES ≥ 0.3 MW

Equipment Type	Limit at Rule Adoption*	Limit effective on future compliance date*
Turbines ≥ 0.3 MW firing at least 60% percent digester gas	18.8 ppm	5 ppm

**All emission limits in parts per million (ppm) are referenced at 15 percent oxygen on a dry basis.*

Cost-Effectiveness Analysis

Staff conducted cost-effectiveness analyses based on the initial NOx limits. The cost-effectiveness to meet 18.8 ppm at 15 percent oxygen on a dry basis is $48,600 per ton of NOx reduced, to be achieved by increased water injection. The average cost-effectiveness to meet 5 ppm at 15% oxygen on a dry basis is >$50,000 per ton of NOx reduced.

BARCT Emission Limits

Staff is proposing an emission limit of 18.8 ppm at 15 percent oxygen on a dry basis. The following table provides the proposed BARCT emission limits for turbines that fire digester gas or a digester gas blend with up to 40 percent natural gas.

TABLE 2-8~~9~~
PROPOSED BARCT EMISSION LIMITS FOR DIGESTER GAS AND DUAL FUEL TURBINES ≥ 0.3 MW

Equipment Type	Limit at Rule Adoption*	Limit Upon Turbine Replacement
Turbines ≥ 0.3 MW firing at least 60% percent digester gas	18.8 ppm	BACT Emission Level

**All emission limits in parts per million (ppm) are referenced at 15 percent oxygen on a dry basis.*

SUMMARY OF BARCT EMISSION LIMITS

Table 2-9~~XI~~ contains a summary of proposed BARCT emission limits effective upon rule adoption and proposed BARCT emission limits effective upon equipment replacement. The facility with turbines permitted at 25 ppm at 15 percent oxygen on a dry basis would be required to meet 18.8 ppm at 15 percent oxygen on a dry basis on or before rule adoption.

TABLE 2-9~~10~~
EMISSION LIMITS AND COMPLIANCE SCHEDULE

Equipment Type	Limit at Rule Adoption*	Limit Upon Unit Replacement
Boilers ≤ 2 MMBtu/hr firing digester gas, digester gas and another fuel, or other fuel	30 ppm*	30 ppm*
Boilers ≤ 2 MMBtu/hr without permitted NOx concentration limits, firing digester gas, digester gas and another fuel, or other fuel	Permit Limit	30 ppm*
Boilers > 2 MMBtu/hr firing at least 90% digester gas	15 ppm*	BACT Limit
Turbines < 0.3 MW in operation after May 3, 2013 firing digester gas, digester gas and another fuel, or other fuel	9 ppm^	9 ppm^
Turbines ≥ 0.3 MW firing at least 60% digester gas	18.8 ppm^	BACT Limit

**All emission limits in parts per million (ppm) are referenced at 3 percent oxygen on a dry basis.*
^All emission limits in parts per million (ppm) are referenced at 15 percent oxygen on a dry basis.

CHAPTER 3: PROPOSED RULE 1179.1

INTRODUCTION

The following information describes the structure of PR 1179.1 and explains the provisions incorporated from other source-specific rules. New provisions and any modifications to existing provisions that were incorporated are also explained.

PROPOSED RULE STRUCTURE

PR 1179.1 will contain the following subdivisions that will contain all the requirements for the applicable equipment:

a) Purpose
b) Applicability
c) Definitions
d) Emission Limits
e) Source Testing
f) CEMS
g) I&M Plans
h) Diagnostic Emission Checks for Boilers and Engines
i) Recordkeeping
j) Other Requirements for Boilers
k) Other Requirements for Engines
l) Schedule for Permit Revisions
m) Exemptions
Attachment 1) I&M Plan Elements
Attachment 2) Boiler Tuning Procedure

PROPOSED RULE 1179.1

Subdivision (a) – Purpose

The purpose of the rule is to limit emissions from combustion equipment located at a POTW. The regulated pollutants subject to PR 1179.1 include NOx, CO, and VOC for engines; and NOx and CO for boilers and turbines.

Subdivision (b) – Applicability

This rule applies to boilers, turbines < 0.3 MW, and engines, located at a POTW that are permitted to fire digester gas, including dual fuel units that are permitted to fire digester gas and another fuel. PR 1179.1 also applies to all turbines ≥ 0.3 MW located at a POTW, regardless of the fuels the unit is permitted to fire, since Rule 1134 requirements (which regulates turbines) specifically excludes turbines located at POTW facilities.

Subdivision (c) – Definitions

Definitions in PR 1179.1 that applied in other source-specific rules are incorporated to define equipment, fuels, and other rule terms. New or modified definitions added to PR 1179.1 are:

- *DIGESTER GAS is gas that is produced by anaerobic decomposition of organic material.*

This definition was added to describe a type of fuel used in equipment that PR 1179.1 applies to. The definition includes fuel derived from anerobic digestion of all organic waste, including sewage and food, that is used for fuel for combustion equipment located at a POTW.

- *DIGESTER GAS UNIT is any combustion equipment subject to this rule permitted to fire digester gas exclusively.*

  This definition was added to describe a type of unit that is applicable to PR 1179.1.

- *DUAL FUEL UNIT is any combustion equipment subject to this rule permitted to fire digester gas and another fuel.*

  This definition was added to describe a type of unit that is applicable to PR 1179.1.

- *ENGINE is any internal combustion equipment that is spark- or compression ignited and burns liquid and/or gaseous fuel to create heat that move pistons to do work.*

  This definition was added to describe a type of equipment applicable to PR 1179.1.

- *SHUTDOWN is the time period that begins when an operator reduces load and which ends in a period of zero fuel flow.*

  This definition is from Rule 1134 and was modified to apply to all equipment types subject to PR 1179.1.

- *STARTUP is the time period that begins when a unit combusts fuel after a period of zero fuel flow and which ends when the unit reaches stable operating conditions.*

  This definition is from Rule 1134 and was modified to apply to all equipment types subject to PR 1179.1.

- *TURBINE is any internal combustion equipment that burns liquid and/or gaseous fuel to create hot gas that expands to move a rotor assembly, with vanes or blades, to do work.*

  This definition was added to describe a type of equipment PR 1179.1 applies to.

- *UNIT is a boiler, turbine, or engine subject to this rule.*

  This definition is added for clarity when referencing equipment subject to the requirements of PR 1179.1.

Subdivision (d) – Emission Limits

This subdivision establishes the NOx and other criteria pollutant emission limits for boilers, turbines, and engines.

Paragraph (d)(1) includes ~~a~~ Table 1, which contains the emission requirements for NOx, CO, and VOC for all the equipment subject to PR 1179.1. These emission requirements would not apply during periods of startup and shutdown, as further explained in paragraph (d)(5) – Startup and Shutdown.

Table 1 Concentration Limits for Boilers (at 3% O_2)

DIGESTER GAS AND DUAL FUEL BOILERS AND PROCESS HEATERS			
EQUIPMENT CATEGORY	NOx (ppm)[1]	CO (ppm)[1]	COMPLIANCE DATE
Rated heat input capacity > 2 MMBtu/hr and firing 90% digester gas or more[2]	15		On or before [*Date of Adoption*]
Rated heat input capacity > 2 MMBtu/hr and firing 100% natural gas	9	400	On or before [*Date of Adoption*]
Rated heat input capacity ≤ 2 MMBtu/hr	30		On or before [*Date of Adoption*]

1 All parts per million (ppm) emission limits are referenced at 3% volume stack gas oxygen on a dry basis and averaged over 15 minutes.

2 Percent digester gas is based on the flowrates and higher heating values of the fuels.

The NOx and CO concentration limits are listed for units fired on 90 percent digester gas or more, based on higher heating values and flowrates of the fuels used, and 100 percent natural gas, along with the implementation schedule.

All following provisions of this rule that apply to boilers would also apply to process heaters.

Boilers > 2 MMBtu/hr:

- Units that currently meet the Rule 1146/1146.1 limits of 15 ppm NOx at 3 percent oxygen on a dry basis can continue to comply with this limit
- All units will continue to meet the same current CO limit of 400 ppm from Rules 1146/1146.1

Any boiler that fires less than 90 percent digester gas would be required to use a weighted emission limit determined by Equation 1, in paragraph (d)(2). Since it is not expected that facilities would fire digester gas with a fuel other than natural gas, the weighted emission limit only applies to boilers that fire digester gas and natural gas simultaneously.

Boilers ≤ 2 MMBtu/hr:

- Units that currently have a permitted NOx limit of 30 ppm at 3 percent oxygen on a dry basis would continue to meet 30 ppm at 3 percent oxygen on a dry basis
- Units without a permitted NOx concentration limit would be exempt from emission limits in Table 1 and paragraph (d)(2), as specified in paragraph (m)(7) of this rule, and would meet 30 ppm at 3 percent oxygen on a dry basis upon burner or boiler replacement, regardless of fuel fired.
- Units will continue to meet a CO concentration limit of 400 ppm at 3 percent oxygen on a dry basis, which is the same current limit for natural gas units covered under Rule 1146.2

<u>Table 1 Concentration Limits for Turbines (at 15% O_2)</u>

The NOx and CO concentration limits are listed for units fired on 60 percent digester gas or more and 100 percent natural gas, along with the implementation schedule.

<table>
<tr><th colspan="4">TURBINES</th></tr>
<tr><th>EQUIPMENT CATEGORY</th><th>NOx (ppm)[3]</th><th>CO (ppm)[3]</th><th>COMPLIANCE DATE</th></tr>
<tr><td>Rating ≥ 0.3 MW and firing 60% digester gas[4] or more</td><td>18.8</td><td rowspan="4">130</td><td>On or before [Date of Adoption]</td></tr>
<tr><td>Simple cycle with rating ≥ 0.3 MW and firing 100% natural gas</td><td>2.5</td><td>On or before [Date of Adoption]</td></tr>
<tr><td>Combined cycle with rating ≥ 0.3 MW and firing 100% natural gas</td><td>2</td><td>On or before [Date of Adoption]</td></tr>
<tr><td><u>Digester gas or dual fuel with r</u><s>R</s>ating < 0.3 MW<s> and firing digester gas, digester gas with another fuel, or natural gas</s></td><td>9</td><td>On or before [Date of Adoption]</td></tr>
</table>

3 All parts per million (ppm) emission limits are referenced at 15% volume stack gas oxygen on a dry basis and averaged over 1 hour.

4 Percent digester gas is based on volume averaged over a 24 hour period.

Turbines greater than or equal to 0.3 MW

- Units are required to meet 18.8 ppm NOx at 15 percent oxygen on a dry basis on or before the date of adoption of PR 1179.1

The above requirements are for turbines that fire 60 percent or more digester gas. Sixty percent was chosen because it reflects the current permit thresholds for the minimum use of digester gas for both of the affected facilities, and is based on volume averaged over a 24 hour period. Any unit that fires 100 percent natural gas would be required to meet the same BARCT emissions levels established in Rule 1134. Rule 1134 requires simple cycle turbines to meet 2.5 ppm at 15 percent oxygen on a dry basis and combined cycle turbines to meet 2 ppm at 15 percent oxygen on a dry basis. There are no units firing 100 percent natural gas at a POTW, currently.

Any turbine that fires less than 60 percent digester gas would be required to use a weighted emission limit determined by Equation 2, in paragraph (d)(3). Since it is not expected that facilities would fire digester gas with a fuel other than natural gas, the weighted emission limit only applies to turbines that fire digester gas and natural gas simultaneously.

The CO emission limit for all turbines is based on that contained in the affected facility permits. If a permit contains a more stringent CO limit than what the rule contains, it must comply with the more stringent limit

Turbines less than 0.3 MW

These digester gas or dual fuel turbines~~, more commonly referred to as microturbines,~~ will be subject to the requirements of PR 1179.1 when firing digester gas, digester gas and another fuel, or the other fuel only. Units that were installed before January 1, 2013 that are permit exempt and not subject to a NOx limit would meet 9 ppm upon turbine replacement. Units would also be subject to the 130 ppm CO concentration limit. Turbines less than 0.3 MW permitted to fire only non-digester gas fuels are~~is~~ not subject to this rule.

Table 1 Concentration Limits for Engines (at 15% O_2)

Digester gas engines or dual fuel engines that are fired on digester gas, digester gas and another fuel, or the other fuel only, are subject to a NOx limit of 11 ppm at 15 percent oxygen on a dry basis, a CO limit of 250 ppm at 15 percent oxygen on a dry basis, and a VOC limit of 30 ppm at 15 percent oxygen on a dry basis. These are the same requirements as those contained in Rule 1110.2. Engines located at a POTW permitted to fire only non-digester gas fuels such as natural gas would continue to comply with all requirements contained in Rule 1110.2 and would not be subject to PR 1179.1.

DIGESTER GAS AND DUAL FUEL ENGINES				
EQUIPMENT CATEGORY	NOx (ppm)[5]	CO (ppm)[5]	VOC (ppm)[6]	COMPLIANCE DATE
Engines > 50 bhp	11	250	30	On or before [*Date of Adoption*]

[5] All parts per million (ppm) emission limits are referenced at 15% volume stack gas oxygen on a dry basis and averaged over 15 minutes.

[6] Parts per million (ppm) emission limit referenced at 15% volume stack gas oxygen on a dry basis, measured as carbon, and averaged over the sampling time required by the test method.

Emission limits for boilers that fire digester gas simultaneously with natural gas – Paragraph (d)(2)

Boilers that fire digester gas and natural gas simultaneously are subject to the digester gas NOx emission limit when firing 90 percent or more digester gas and 10 percent or less natural gas. If the natural gas percentage threshold is exceeded, then the unit must comply with a weighted average limit, taking into account the compliance limits of both fuels as well as their individual heat inputs and flowrates. Equation 1 in PR 1179.1 is the same equation that is currently contained in Equations 1146-1 and 1146.1-1 of the December 7, 2018 amended versions of Rules 1146 and 1146.1. Flowrate and units were added for clarity in determining the heat input value as required in Rules 1146 and 1146.1, Equations 1146-1 and 1146.1-1, respectively. Owners and operators of these units must comply with either the weighted emission limit or with the natural gas NOx limit.~~,~~ The digester gas higher heating value used in the equation must be obtained using an approved procedure by the South Coast AQMD. Approved South Coast AQMD procedures include submitting digester gas samples for laboratory analyses and using portable monitoring devices. A representative sample of the facility's digester gas would be allowed as long as this same gas is sent to the subject boiler. The flowrates of the fuels used must be obtained using an approved non-resettable totalizing fuel flow meter. The flowrate must be obtained at the time compliance is determined and the digester gas sample used to obtain the higher heating value must be collected no earlier than 30 days before compliance is determined, to ensure there is accurate representation of the digester gas.

$$\text{Weighted Limit} = \frac{(CL_A \; x \; Q_A \; x \; V_A) \; + \; (CL_B \; x \; Q_B \; x \; V_B)}{(Q_A \;\; x \; V_A) + (Q_B \;\; x \; V_B)} \qquad \text{(Equation 1)}$$

Where:

CL_A = compliance limit in Table 1 when firing 90% digester gas or more

Q_A = higher heating value of digester gas in Btu per standard cubic foot (scf)

V_A = flowrate of digester gas in scf per unit of time

CL_B = compliance limit in Table 1 when firing 100% natural gas

Q_B = higher heating value of natural gas in Btu per scf

V_B = flowrate of natural gas in scf per unit of time

Emission limits for turbines ≥ 0.3 MW that fire less than 60 percent digester gas simultaneously with natural gas – Paragraph (d)(3)

Turbines ≥ 0.3 MW that fire more than 40 percent natural gas and less than 100 percent natural gas are subject to a weighted emission limit calculated by Equation 2. The digester gas higher heating value used in the equation must be obtained using an approved procedure by the South Coast AQMD. Approved South Coast AQMD procedures include submitting digester gas samples for laboratory analyses and using portable monitoring devices. A representative sample of the facility's digester gas would be allowed as long as this same gas is sent to the subject turbine. The flowrates of the fuels used must be obtained using an approved non-resettable totalizing fuel flow meter. The flowrate must be obtained at the time compliance is determined and the digester gas sample used to obtain the higher heating value must be collected no earlier than 30 days before compliance is determined, to ensure there is accurate representation of the digester gas.

$$\text{Weighted limit} = \frac{((CL_A + 18.1) \text{ x } Q_A \text{ x } V_A) + (CL_B \text{ x } Q_B \text{ x } V_B)}{(Q_A \text{ x } V_A) + (Q_B \text{ x } V_B)} \qquad \text{(Equation 2)}$$

Where:

CL_A = compliance limit in Table 1 when firing 60% digester gas or more

Q_A = higher heating value of digester gas in Btu per scf

V_A = flowrate of digester gas in scf per unit of time

CL_B = compliance limit in Table 1 when firing 100% natural gas

Q_B = higher heating value of natural gas in Btu per scf

V_B = flowrate of natural gas in scf per unit of time

Equation 2 adds a correction factor of 18.1 to account for the allowance of up to 40 percent natural gas to be fired when complying with 18.8 ppm at 15 percent oxygen on a dry basis.

Averaging Times for Units with CEMS – Paragraph (d)(4)

PR 1179.1 provides averaging time requirements for boilers, turbines, and engines with CEMS. The proposed averaging times are as follows:

- Boilers: Fixed interval of 1 clock hour for NOx and CO
- Turbines: Rolling period of 1 hour
- Engines (same as current Rule 1110.2 requirements):
    - Fixed interval of 1 hour
    - Fixed interval of 24 hours when at or below 11 ppm at 15 percent oxygen on a dry basis NOx and 250 ppm at 15 percent oxygen on a dry basis CO (contained in permit to operate before November 1, 2019)
    - Fixed interval of 48 hours when at or below 9.9 ppm at 15 percent oxygen on a dry basis NOx and 225 ppm CO at 15 percent oxygen on a dry basis (contained in permit to operate)

Startup and Shutdown – Paragraph (d)(5)

Startup and shutdown requirements are provided in PR 1179.1 for boilers, turbines, and engines and are as follows:

- Boilers without SCR: Not longer than is necessary for the proper operation of the boiler for startup and not longer than 6 hours for startup or shutdown (same as current Rule 1146 requirements)
- Boilers with SCR: Not longer than is necessary to reach minimum catalyst operating temperature for startup and not longer than 6 hours for startup or shutdown
- Boilers ≥ 5 – 40 MMBtu/hr cannot exceed 10 scheduled startup/shutdown events per month
- Boilers > 40 MMBtu/hr cannot exceed 10 scheduled startup/shutdown events per year

Maximum scheduled startup and shutdown requirements reflect current requirements in Rule 429. Boilers currently subject to Rule 1146 are required to comply with Rule 429. Since digester gas and dual fuel boilers would no longer be subject to Rule 1146, Rule 429 requirements were included in PR 1179.1. Facilities are required to submit a startup and shutdown schedule by January 1 of each year to the Executive Officer and notify the Executive Officer prior to each scheduled startup and shutdown event with the dates, times, and duration of the scheduled startup and shutdown and of any other process variables requested by the Executive Officer. Scheduled startup and shutdown events include, but are not limited to, those planned for maintenance, service, and tuning, and do not include startups or shutdowns triggered by a demand response system.

- Turbines without SCR: Startup cannot exceed the time at which control equipment is properly operating and cannot exceed 3 hours. Control equipment includes any mechanism that reduces NOx emissions for the purpose of meeting the emission limits of Table 1 or paragraph (d)(3), such as water injection or dry low emission systems.
- Turbines with SCR: Not longer than is necessary for the SCR to properly operate and not longer than 2 hours.
- Engines (same as current Rule 1110.2 requirements):
    - Not longer than 30 minutes unless a longer time period, less than 2 hours, is specified in the permit
    - Not longer than 4 operating hours for major repairs or installation of catalytic control equipment (as explained in the staff report for the November 2019 amendments to Rule 1110.2)

Facilities are required to comply with the startup and shutdown requirements of PR 1179.1 upon adoption, as well as startup and shutdown requirements contained in a unit permit. In cases where permit requirements are more stringent than those in PR 1179.1, in order to comply with other rule or regulation requirements, the facility shall comply with the more stringent requirement.

Prohibition of liquid fuel – Paragraph (d)(6)

PR 1179.1 contains a prohibition on the use of any liquid fuel, such a diesel, for the operation of any turbine at a POTW. This provision would not apply to emergency use turbines as described in the proposed exemptions under subdivision (m).

Subdivision (e) – Source Testing

For units and for pollutants not subject to CEMS, PR 1179.1 provides a source testing schedule in Table 2.

TABLE 2
SOURCE TESTING SCHEDULE

Equipment Category	Frequency	Pollutant	Elapsed Time Prior to Conducting Source Test[1]
Boilers ≥ 10 MMBtu/hr	Every 3 years from the date the previous source test was required,	NOx, CO	At least 250 operating hours

	no later than the last day of the calendar month that the test is due		or at least 30 calendar days
Boilers < 10 MMBtu/hr and > 2 MMBtu/hr	Every 5 years from the date the previous source test was required, no later than the last day of the calendar month that the test is due		
Turbines with output capacity rating ≥ 2.9 MW	Every year from the date the previous source test was required, no later than the last day of the calendar month that the test is due		At least 40 operating hours or at least 7 calendar days
Turbines with output capacity rating < 2.9 MW	Every 3 years from the date the previous source test was required, no later than the last day of the calendar month that the test is due or every 8,760 operating hours, whichever occurs later		
Engines	Every 2 years from the date the previous source test was required, no later than the last day of the calendar month that the test is due, or every 8,760 operating hours, whichever occurs first[2]	NOx, CO, and VOC reported as carbon	

1 Elapsed time subsequent to any tuning or servicing, unless tuning or servicing is due to an unscheduled repair.

2 Frequency may be reduced once every 3 years if the engine has operated less than 2,000 hours since the last source test. If the engine has not been operated before the date a source test is due, the source test shall be conducted by the end of 7 consecutive days or 15 cumulative days of resumed operation. An owner or operator of the engine shall keep sufficient operating records to demonstrate that it meets the requirements for extension of the source testing deadlines.

The boiler requirements are the same as those contained in Rules 1146/1146.1, while the turbine requirements reflect those contained in Rule 1134. The source testing requirements would apply to all turbines, including those less than 0.3 MW. Lastly, the engine requirements reflect the same requirements currently contained in Rule 1110.2.

Other source testing requirements, which come from existing source testing requirements from other source-specific rules, such as Rule 1110.2, are contained in PR 1179.1 and apply to all the applicable equipment types. All equipment types would be required to source test no later than the last day of the calendar month that the source test is due.

Initial Source Testing - Paragraph (e)(2)

The owner or operator of any unit required to source test by Table 2, that has not conducted an initial source test for that unit, would be required to conduct a source test within 12 months from the adoption of PR 1179.1.

Source Test Protocol Submittal and Scheduling - Paragraph (e)(3)

PR 1179.1 provides 60 days before a scheduled source test date for the owner or operator to submit a source test protocol for approval. A new requirement is included in subparagraph (e)(3)(A) that requires a new submittal of a source testing protocol if any modification to the equipment results in a change to the permit, if any emission limits have changed, or at the request of the Executive Officer. A new submittal may be required, for example, if the prior source testing protocol is outdated. The owner or operator is allowed 90 days from the date the approval of the source test protocol was electronically distributed to conduct the source test.

Source Test Protocol Requirements - Paragraph (e)(4)

Contains requirements for the information required for submitting a protocol, in addition to further requirements pertaining to engines under subparagraph (e)(4)(A), which are consistent with current Rule 1110.2 requirements.

Source Test Date Notification - Paragraph (e)(5)

Contains requirements for notification of a scheduled source test.

Approved Contractor and Test Methods - Paragraph (e)(6):

Contains requirements for source testing that is to be conducted by a South Coast AQMD-approved contractor. A listing of source testing methods is contained in Table 3.

TABLE 3
SOURCE TESTING METHODS

Pollutant	**Test Methods**
NOx	South Coast AQMD Test Methods 100.1 or 7.1
CO	South Coast AQMD Test Methods 100.1 or 10.1, or EPA Test Method 10
CO_2 and O_2	South Coast AQMD Test Method 3.1 or 100.1
VOC	South Coast AQMD Test Methods 25.1 or 25.3, excluding ethane and methane

Source Testing Facilities – Paragraph (e)(7)

Contains requirements for physical accommodations that allow for a source test to be conducted.

Operating Conditions During Source Testing for Boilers and Turbines - Paragraph (e)(8)

Contains requirements on conducting source tests for boilers and turbines in the as-found operating condition, and that no testing should be completed during periods of startup, shutdown, or under breakdown conditions. Also requires a minimum sampling time for boilers and turbines of 15 minutes.

Operating Conditions During Source Testing for Engines - Paragraph (e)(9)

Contains specific operating load (actual duty cycle) requirements for the source testing of engines, which are the same requirements as those currently under Rule 1110.2.

Submittal of Completed Source Test - Paragraph (e)(10)

Facilities are required to submit source test reports within 60 days of the completed source test.

Using Relative Accuracy Test Audits (RATAs) In Lieu of a Source Test - Paragraph (e)(11)

Contains an allowance for RATAs to be used in lieu of a source test, provided that the RATA is conducted within the same calendar that the source test is required. It should be noted that Proposed Rules 218.2 and 218.3 are currently under development and may~~will~~ contain enhanced provisions and requirements for units operating with CEMS that will apply to units covered by PR 1179.1.

Subdivision (f) – CEMS

This subdivision contains the requirements for the installation, operation, and maintenance of CEMS equipment. Many of these requirements are also contained in Rule 218 and 218.1, which currently address monitoring requirements and performance specifications. As noted previously, Proposed Rules 218.2 and 218.3 are currently under development and may~~will~~ contain enhanced monitoring and performance specification requirements. Equipment subject to this rule would also be required to comply with Rules 218/218.1 as well as Rule 218.2/218.3, upon adoption. Table 4 in subdivision (f) contains the thresholds for boilers, turbines, and engines for requiring CEMS, consistent with current requirements in Rules 1146, 1134, and 1110.2, respectively.

TABLE 4
UNITS REQUIRING CEMS

Equipment Type	Threshold	Pollutant(s)
Boilers	Rated heat input capacity > 40 MMBtu/hr and an annual heat input > 200 x 10^9 Btu per year	NOx
Turbines	Output capacity rating ≥ 2.9 MW	NOx

Engines	Output capacity rating ≥ 1000 bhp and operating more than 2 million bhp-hr per calendar year	NOx, CO
	Combined output capacity rating ≥1500 bhp and a combined fuel usage of >16 x 10^9 Btu per year, for engines at the same location[1]	

1 ~~Engines as of~~Effective October 1, 2007, engines located within 75 feet of another engine (measured from engine block to engine block) are considered to be at the same location.

Turbine Parameter Monitoring - Paragraph (f)(1)

Provides parameter monitoring requirements, specific to turbines using CEMS, including flowrate of fuel gases, ratio of water or steam added, if applicable, elapsed time of operation, and turbine output in MW.

CEMS Requirements for Engines - Paragraph (f)(2)

Subparagraphs (f)(2)(A) and (f)(2)(B) contain CEMS requirements for engines, as well as an aggregate threshold requirement for co-located engines, as well as exceptions already applicable to these engines in Rule 1110.2.

Subparagraph (f)(2)(C) contains new requirements introduced into Rule 1110.2 during the November 2019 amendments which allow engines 1,000 bhp and greater and less than 1,200 bhp to conduct weekly diagnostic checks in lieu of installing a CEMS. However, if there are three or more combined emissions exceedances in any 12-month period as shown with a South Coast AQMD test using a portable analyzer or a source test, the owner or operator would be required to install CEMS.

Subparagraph (f)(2)(D) provides requirements for installing CEMS upon exceedance of the threshold.

Subparagraph (f)(2)(E) allows for an existing NOx CEMS to be taken out of service for up to a 2 week time period to add CO CEMS.

Subparagraph (f)(2)(F) provides additional requirements for monitoring and for allowing relative accuracy testing audits (RATAs) to be performed on the same testing schedule for source tests, despite the annual RATA requirements of Rule 218.1.

Subparagraph (f)(2)(G) provides additional clarity for engines installed at the same location. New engines cannot be installed farther than 75 feet away from each other to avoid circumvention of the aggregate engine CEMS threshold.

Subparagraph (f)(2)(H) provides requirements for new engines that are issued a permit to construct to comply with CEMS or I&M plan requirements upon commencement of engine operation.

Subdivision (g) – I&M Plans

This subdivision contains the I&M plan requirements that are consistent with those currently in Rule 1110.2. Owners and operators are required to have an I&M plan approved for their facility that contains the items that are listed in Attachment 1 of PR 1179.1, if the facility has an engine without a NOx and CO CEMS. Attachment 1 contains the same elements as Attachment 1 of Rule 1110.2. Since PR 1179.1 will apply to digester gas fired engines, owners and operators of engines that are covered by both Rule 1110.2 for exclusively natural gas and 1179.1 for digester gas would require one I&M plan for each rule, if applicable.

Subdivision (h) – Diagnostic Emission Checks for Boilers and Engines

This subdivision contains requirements that are consistent with current requirements in Rules 1146/1146.1 and in Rule 1110.2. Diagnostic emission checks are required to be conducted by trained staff in accordance with the Combustion Gas Periodic Monitoring Protocol for boilers and engines subject to Rule 1146, 1146.1, and 1110.2. The minimum sampling time for diagnostic emission checks is 15 minutes.

Diagnostic Checks for Boilers - Paragraph (h)(1)

Provides diagnostic emission check requirements for boilers. Testing frequency is separated by boiler size and allows for the owner or operator to resolve any problems in the event of an emissions exceedance. If the diagnostic emission check frequency has been reduced to quarterly or every 2,000 unit operating hours, whichever occurs later, for boilers greater than or equal to 5 MMBtu/hr, or semi-annually or every 4,000 unit operating hours, whichever occurs later, for boilers great than 2 MMBtu/hr and less than 5 MMBtu/hr, the facility will continue to perform diagnostic emission checks in accordance with that schedule upon rule adoption. Any diagnostic emission check conducted by South Coast AQMD staff that finds an emissions exceedance would be a violation.

Diagnostic Checks for Engines - Paragraph (h)(2)

Provides diagnostic emission check requirements for engines, including testing frequency and additional requirements for lean-burn engine operators. If the diagnostic emission check frequency has been reduced to monthly or every 750 unit operating hours, whichever occurs later, the facility will continue to perform diagnostic emission checks in accordance with that schedule upon rule adoption. As with boilers, any diagnostic emission check conducted by South Coast AQMD staff that finds an emissions exceedance will be a violation.

Subdivision (i) – Recordkeeping

This subdivision harmonizes the recordkeeping requirements for the various types of equipment that will be subject to PR 1179.1. PR 1179.1 would additionally require owners or operators to maintain maintenance, service and tuning records. Subdivision (i) would require records to be retained by facility owners and operators for 5 years. Other source-specific rules contained shorter records retention timeframes (such as 2 years). Accumulation of the records would begin upon date of adoption.

Recordkeeping for Boilers - Paragraph (i)(1)

Subparagraphs (i)(1)(A) and (i)(1)(B) provide recordkeeping requirements consistent with Rule 429 – Start-Up and Shutdown Exemption Provisions for Oxides of Nitrogen that boilers subject to Rule 1146 are subject to~~currently complying with~~.

Recordkeeping for Turbines - Paragraph (i)(2)

Provides recordkeeping requirements for operators of turbines. Records of hours of operation, type of fuel used, and startup and shutdown times are required. In addition, this paragraph also requires recordkeeping of emission control system operation and maintenance to verify continuous operation while the turbine is in operation and equipment requirements to verify certain parameters.

Recordkeeping for Engines - Paragraph (i)(3)

Provides the monthly operating log requirements for owners and operators of engines subject to PR 1179.1.

Recordkeeping for Units Required to Conduct Source Test - Paragraph (i)(4)

Requires tuning and servicing records as well as records of the hours of operation of a unit since any tuning or servicing prior to conducting a source test.

Subdivision (j) – Other Requirements for Boilers

This subdivision contains additional requirements specific to boilers and consistent with current requirements from Rules 1146, 1146.1, and 1146.2.

Derating Boilers - Paragraph (j)(1)

Provides a requirement that an owner or operator cannot derate any boiler to less than or equal 2 MMBtu/hr to circumvent permitting and emissions requirements.

Maintenance for Small Boilers - Paragraph (j)(2)

Provides maintenance and recordkeeping requirements for small boilers rated less than or equal to 2 MMBtu/hr.

Subdivision (k) – Other Requirements for Engines

This subdivision contains other requirements that are specific for engines and that are consistent with current requirements of Rule 1110.2 that pertain to reporting, breakdowns, and other equipment requirements.

Engine Breakdowns - Paragraph (k)(1)

Provides the requirements for breakdown conditions or emissions exceedances from diagnostic emission checks. Subparagraph (k)(1)(B) contains excess emission thresholds for breakdowns in

Table 5. These are the same requirements that were adopted during the December 2015 amendments to Rule 1110.2 to limit the number of breakdowns that can occur during any calendar quarter as a way to provide a quantification of excess emissions due to these types of events.

TABLE 5 EXCESS EMISSION CONCENTRATION THRESHOLDS FOR BREAKDOWNS		
Equipment Category	NOx (ppmvd)[1]	CO (ppmvd)[1]
Lean-Burn Engines	45	250
Rich-Burn Engines	150	2000

[1] Corrected to 15% oxygen

<u>Totalizing Meters for Engines - Paragraph (k)(2)</u>

Provides requirements for maintaining a non-resettable totalizing time meter for engines.

<u>Air-to-Fuel Ratio Controller for Engines - Paragraph (k)(3)</u>

Provides requirements for maintenance of combustion controls for engines without CEMS.

<u>Breakdown Reporting for Engines - Paragraph (k)(4)</u>

Provides reporting requirements for breakdowns that result in emissions exceedances along with the required documentation for these events. The quarterly reports that are also required for natural gas engines under Rule 1110.2 would also be required for digester gas engines under PR 1179.1. These reports would contain each occurrence of a breakdown, fault, malfunction, alarm, engine or control system parameter out of range, or a diagnostic emission check that results in an emissions exceedance.

Subdivision (l) – Schedule for Permit Revisions

Provides deadlines for permit applications to be submitted for revising equipment permits and I&M plans to reflect PR 1179.1. Facilities would only submit applications for equipment with permits that reference other source specific-rules no longer applicable once PR 1179.1 is adopted. Title V facilities would have until the next Title V permit renewal application is due to submit applications for each piece of equipment subject to PR 1179.1 and an I&M plan per facility, if applicable. Non-Title V facilities would submit applications by the proposed dates, depending on the type of equipment.

- Applications for each existing boiler > 2 MMBtu/hr would be required to be submitted on or before January 1, 2023
- Applications for each existing boiler ≤ 2 MMBtu/hr would be required to be submitted on or before July 1, 2023

- Applications for each existing engine and I&M plans for ~~facility~~ each facility with at least one engine subject to this rule would be required to be submitted on or before January 1, 2024
- Applications for each existing turbine would be required to be submitted on or before July 1, 2024

Subdivision (m) – Exemptions

Low-Use Boilers > 2 MMBtu/hr - Paragraph (m)(1)

Provides low fuel use exemptions for any boilers previously subject to Rule 1146 that were in operation before September 5, 2008 with an annual heat input usage less than or equal to 9.0×10^9 Btu per year (90,000 therms). Owners and operators with such units at POTWs would be exempt from the emission limits in Table 1 or paragraph (d)(2), but shall not operate the boiler in a manner that exceeds 30 ppm, provided the owner or operator follows the tune up procedures in Attachment 2 for that boiler. Any boiler that exceeds the 90,000 therm threshold is required to demonstrate compliance with the 15 ppm emission limit within 18 months of the exceedance.

Special Use Turbines - Paragraph (m)(2)

Provides exemption to turbines that are used only for firefighting or flood control. In addition, an exemption from PR 1179.1 requirements is provided for emergency standby turbines, which are defined here and in Rule 1134. An owner or operator must maintain an hour meter and a log to verify that each emergency standby turbine does not exceed a usage limit of 200 hours per year. If the usage threshold is exceeded, the owner or operator would be required to submit a permit application to meet the applicable compliance limits of PR 1179.1.

Non-Digester Gas Fired Boilers, Turbines < 0.3 MW, and Engines - Paragraph (m)(3)

Provides an exemption for units permitted to fire only non-digester gas fuels. Boilers at POTWs not permitted to fire any amount of digester gas would remain subject to the requirements of the Rule 1146 Series, depending on size (Rules 1146, 1146.1, 1146.2). Engines not permitted to fire any amount of digester gas would remain subject to the requirements of Rule 1110.2. Turbines less than 0.3 MW not permitted to fire any amount of digester gas are not subject to PR 1179.1.

Low-Use Engines - Paragraph (m)(4)

Provides an exemption for engines that operate 200 hours or less per year. The engine usage would need to be verified with the installation of a non-resettable engine hour meter and with the maintenance of an operating log. Staff identified low-use digester gas engines that would be exempt from PR 1179.1.

Exempted Engines - Paragraph (m)(5)

PR 1179.1 would not apply to laboratory engines used in research and testing purposes, engines operated for purposes of performance verification and testing of engines, auxiliary engines used to power other engines or gas turbines during start-ups, or portable engines that are registered under the state registration program pursuant to Title 13, Article 5 of the CCR.

Permit Exempt Turbines < 0.3 MW - Paragraph (m)(6)
Provides an exemption from rule requirements for turbines < 0.3 MW that were in operation before May 3, 2013 and are currently permit exempt.

Boilers Without Permitted NOx Concentration Limits - Paragraph (m)(7)
Provides an exemption for boilers without permitted NOx concentration limits. The boilers would be exempt from the emission limits in Table 1 or paragraph (d)(2). The emission limits in Table 1 and paragraph (d)(2) become effective upon a burner or boiler replacement.

Commissioning Period for Turbines and Engines – Paragraph (m)(8)
Provides an exemption from the emission limits in Table 1 or paragraph (d)(3) for the commissioning of new engines and turbines and specifies the commissioning period for each equipment type. Operators requesting this exemption must have these time periods as permit conditions.

Low-Use Boilers ≤ 2 MMBtu/hr Firing Natural Gas - Paragraph (m)(9)
Provides an exemption from the natural gas emission limits for boilers ≤ 2 MMBtu/hr that use less than 9,000 therms of natural gas, provided the natural gas usage is verified with an in line fuel meter or the annual operating hours are recorded by a timer and using a method described in subparagraphs (m)(9)(A) through (m)(9)(C) to calculate fuel use. These requirements are consistent with those in Rule 1146.2.

Engines Under Variances - Paragraph (m)(10)
Provides an exemption from the rule for five engines operated by San Bernardino Municipal Water Department currently operating under the variance issued by South Coast Air Quality Management District Hearing Board on December 20, 2018 for the term of the variance. Engines operating under this variance are expected to be decommissioned by the agency as part of implementing a Digester Gas Beneficial Use Program. The five engines remain subject to Rule 1110.2, in addition to the conditions of the variance, until the engines are removed from operation.

San Bernardino Municipal Water Department is implementing a fuel cell project that will utilize digester gas currently supplying the engines under the variance. Once the fuel cell project commences operation, the engines will no longer operate. However, if the engines continue to operate after the variance expires, the engines would no longer be exempt from PR 1179.1.

Attachment 1 – I&M Plan Elements

Attachment 1 applies for engines with I&M plans subject to PR 1179.1 subdivision (g). These parameters and procedures are consistent with those contained in Rule 1110.2.

Attachment 2 – Equipment Tuning Procedure for Forced-Draft Boilers, Steam Generators, and Process Heaters

Attachment 2 applies to boilers using the low-use exemption in paragraph (m)(1) and provides the procedure for tuning boilers, required at least twice per year by paragraph (m)(1). These parameters and procedures are consistent with those contained in Rules 1146 and 1146.1.

CHAPTER 4: IMPACT ASSESSMENTS

INTRODUCTION

POTW equipment is currently subject to source specific rules, with the exception of turbines greater than or equal to 0.3 MW. PR1179.1 will contain all applicable provisions from source specific rules that facilities are currently subject to. In addition, PR 1179.1 contains provisions that reflect conditions on facility equipment permits. The emission limit proposed in PR 1179.1 will reduce emissions from three turbines located at one facility.

EMISSION REDUCTIONS

PR 1179.1 will result in emission reductions from turbines ≥ 0.3 MW. Boilers and engines will remain at the current rule limits and/or permit limits, with the exception of four boilers that are not permitted with a NOx concentration limit.~~ Reductions for the boilers without permitted NOx concentration limits were not determined because baseline emissions are not known. The reductions for the boilers without permitted NOx concentration limits are estimated to be negligible.~~ Baseline emissions for turbines were determined using 2019 Annual Emissions Reports (AER).

Emission Reduction Estimate for Turbines

There six turbines located at two POTWs greater than or equal to 0.3 MW that fire either digester gas only or digester gas and another fuel. The emission limit proposed in PR 1179.1 will reduce emissions from three turbines located at one facility. The total baseline emissions for the facility impacted by the proposed emission limit are 149,156 pounds per year or 0.20 tons per day. The three turbines are permitted at 25 ppm at 15 percent oxygen on a dry basis. The baseline emissions for the facility operating the other three turbines are 96,854 pounds or 0.13 tons per day. These turbines are permitted at 18.8 ppm at 15 percent oxygen on a dry basis. The proposed emission limit of 18.8 ppm would only affect the three turbines permitted at 25 ppm. The proposed emission limit would become effective upon rule adoption and the NOx emission reductions that would be achieved are 0.05 tons per day.

COST-EFFECTIVENESS

The California Health & Safety Code (H&SC) 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. The costs for the control technology includes purchasing, installation, operating, and maintaining the control technology. Emissions reductions were based on the 2019 AER and the most recent source test data for turbines. The 2016 AQMP established a cost-effectiveness threshold of $50,000 per ton of NOx reduced. The cost-effectiveness is estimated based on the present worth value of the control cost, which is calculated according to the capital cost (initial one-time equipment, installation, and startup costs) plus the annual operating cost (recurring expenses over the useful life of the control equipment times a present worth factor). In the cost-effectiveness calculation, staff assumed a uniformed series present worth factor (PWF) at a 4% interest rate and a 25-year equipment life expectancy.

PWV = TIC + (PWF x AC)

PWV = present worth value ($)
TIC = total installed cost ($)
AC = annual cost ($)
PWF = uniform series present worth factor (15.622)

Boilers ≤ 2 MMBtu/hr

A cost-effectiveness analysis was conducted for boilers 1-2 MMBtu/hr to meet a NOx concentration limit of 12 ppm at 3 percent oxygen on a dry basis and boilers < 1 MMBtu/hr to meet a NOx concentration limit of 20 ppm at 3 percent oxygen on a dry basis. Staff used costs from the Rule 1146 series cost analysis of low NOx burners for units ≤ 2 MMBtu/hr. The cost for low NOx burner replacements for boilers ≤ 2 MMBtu/hr is $20,000. This cost was used to calculate cost-effectiveness. The cost-effectiveness to replace existing burners on boilers 1-2 MMBtu/hr with a burner that can meet a NOx concentration limit of 12 ppm at 3 percent oxygen on a dry basis is greater than $50,000 per ton of NOx reduced. The cost-effectiveness to replace existing burners on boilers < 1 MMBtu/hr with a burner that can meet a NOx concentration limit of 20 ppm at 3 percent oxygen on a dry basis is greater than $50,000 per ton of NOx reduced.

Boilers > 2 MMBtu/hr

A cost-effectiveness analysis was conducted for boilers to meet 12 ppm at 3 percent oxygen on a dry basis. Staff used costs from the Rule 1146 series cost analysis of low NOx burners for units > 2 MMBtu/hr. Equipment costs ranged from $40,000-$350,000 depending on the size and the installation costs ranged from $25,000-$125,000 depending on size. The average cost for a low NOx burner that can meet a NOx concentration limit of 12 ppm at 3 percent oxygen on a dry basis with installation is $90,300. The average cost-effectiveness to retrofit boilers with a burner that can meet a NOx concentration limit of 12 ppm at 3 percent oxygen on a dry basis is greater than $50,000 per ton of NOx reduced.

Turbines ≥ 0.3 MW

Staff obtained costs for control equipment from a variety of sources that included facilities, suppliers, and cost-estimation tools. The cost for control equipment considers capital costs and annual costs. Capital costs are one-time costs that cover the components required to assemble a project. These costs include, but are not limited to, equipment, installation, permitting, consulting, and testing. Annual costs are any recurring costs required to operate equipment. These costs include operating and maintenance (O&M) costs such as electricity, monitoring, and costs for consumables.

Selective Catalytic Reduction

SCR costs were obtained from facilities, U.S EPA’s Air Pollution Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR), two engineering consultants, one catalyst supplier, and applicable costs from the Rule 1110.2 cost analysis for SCR (2012 Technology Assessment). The costs for SCR considered retrofitting three turbines that currently do not utilize SCR. The design parameters used to obtain SCR cost estimates and costs from various sources are shown in Table 4-1 and Table 4-2.

Table 4-1

SCR DESIGN PARAMETERS

HHV	665 Btu/scf
Inlet NOx	22 ppm
Removal efficiency	90%
Exhaust flowrate	~325,000 lbs/hr
Operating days/year	365
Operating life of catalyst	24,000 hours
Ammonia slip	5 ppm
Inlet temperature	866 F
Electricity	$0.19/kwh - $0.25/kwh

Table 4-2
SCR COST ESTIMATES

Source	Capital Cost	Annual Costs
EPA Cost Manual	$8.3 million	$1.2 million
Supplier A	$8.0 million	$489,5000
Supplier B	2.5 million*	$450,000
Rule 1110.2 staff report (11/19)	$1.4 million - $6.6 million	EPA Cost Manual
Facility A	Unavailable	$38,000 (3 SCRs) new - no catalyst replacement^
Facility B	Unavailable	$48,000 (5 SCRs) new - no catalyst replacement^
Average cost for 3 SCRs	$7.6 million	$458,5000

* Identified as outlier and not included in the average capital cost.

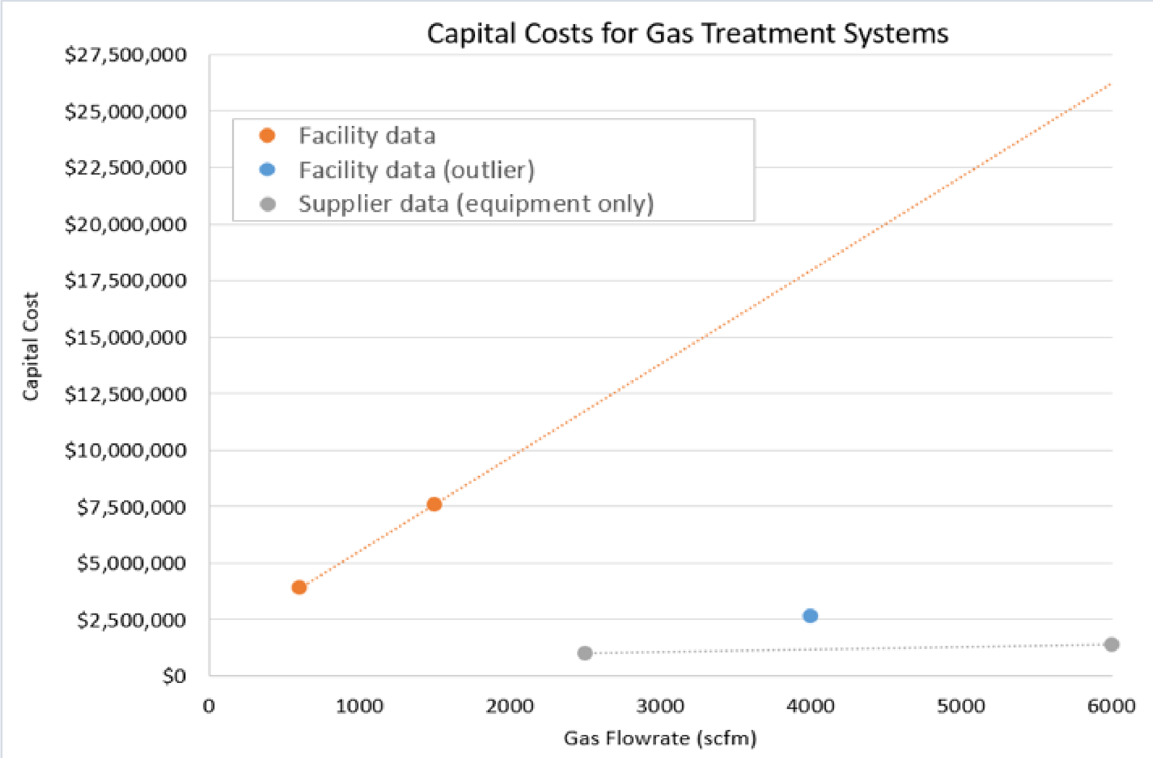
^ Annual costs provided by Facilities A and B did not include cost for catalyst due to new installations that have not required a catalyst replacement. An added annual cost of $33,000 (not shown in table) was added to Facility A's and Facility B's annual costs for catalyst. The added costs were included in the average annual costs.

Gas Treatment

Costs for gas treatment were obtained from POTWs and landfills within California. Costs reflect gas treatment systems designed to remove siloxanes to < 100 ppb from gas streams that have reported inlet siloxane levels of < 15 ppm.

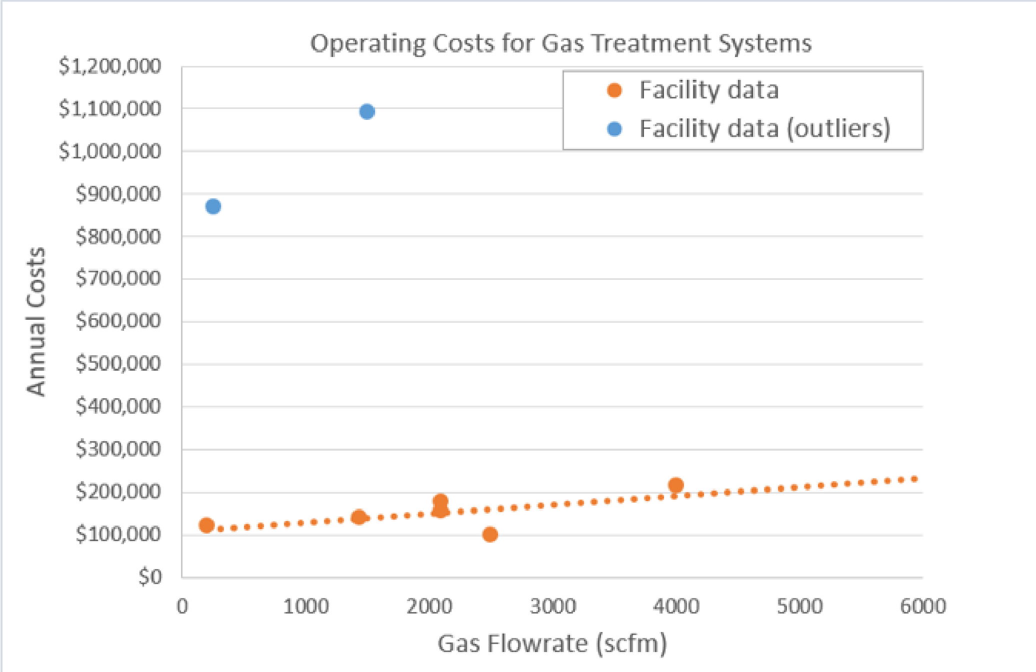
One outlier for cost information was identified and the data was not considered in determining capital costs. One supplier provided two cost estimates for two flowrates. The supplier provided only equipment costs. Figure 4-1 shows the data used to determine a capital cost for a gas treatment system in relation to gas flowrate.

Figure 4-1 – Capital Costs for Gas Treatment Systems



Annual costs for gas treatment systems were provided by eight facilities. The facilities had reported siloxane levels between 4.4 ppm – 15 ppm. One facility treated digester gas to PUC pipeline quality gas. This facility had the highest operating costs of approximately one million dollars with over half the costs attributed to electricity needs. Four other facilities have not considered electricity as a significant cost in the costs they provided for their gas treatment systems. The facility whose cost information reflected a gas treatment system that treats gas to PUC pipeline quality was identified as an outlier. One other facility's data was identified as an outlier. Figure 4-2 shows the data obtained from facilities for annual costs of gas treatment systems in relation to gas flowrate.

Figure 4-2 – Operating Costs for Gas Treatment Systems



The data used to determine cost-effectiveness to meet 5 ppm at 15 percent oxygen on a dry basis was identified for a gas treatment system that requires treatment of 6,000 scfm of digester gas. The capital cost determined was $26,250,000 and the annual O&M costs were $250,000.

New Turbines

Costs were analyzed for new turbines that can meet 5 ppm at 15 percent oxygen on a dry basis with existing SCRs. The facility that currently uses SCR would be required to replace their turbines with inlet~~uncontrolled~~ NOx of 213 ppm at 15 percent oxygen on a dry basis ~~turbines~~ for turbines with inlet~~uncontrolled~~ NOx of 15 ppm at 15 percent oxygen on a dry basis, to meet 5 ppm at 15 percent oxygen on a dry basis. Costs for new turbines that can meet 15 ppm at 15 percent oxygen on a dry basis were obtained from the EPA Catalog of CHP Technologies. The EPA Catalog of CHP Technologies estimates capital costs for new turbines at $1.2 - $1.5 million per megawatt, and annual costs at $0.0092-$0.0093 per kilowatt-hour. The three turbines currently equipped with SCR have a power output capacity of 41.85 MW. The capital cost at $1.5 million/MW is $62,800,000. The annual cost at $0.0093/kwh is $3,400,000. The cost-effectiveness for the turbines with SCR to meet 5 ppm at 15 percent is $253,200, including stranded assets.

Water Injection

Staff obtained costs from one facility and one demineralized water supplier to determine the cost-effectiveness of a turbine NOx concentration limit of 18.8 ppm limit at 15 percent oxygen on a dry basis. The facility stated that up to 8,000 gallons per day, per turbine, of demineralized water is needed to meet a NOx concentration limit of 18.8 ppm at 15 percent oxygen on a dry basis and has stated that a general cost for demineralized water is ten times the cost of potable water. Utility water rates were obtained from LADWP's website that stated a cost of $0.0071 per gallon as the industrial water rate. At ten times the utility water rate ($0.071 per gallon), the annual cost to meet a NOx concentration limit of 18.8 ppm at 15 percent oxygen on a dry basis is $204,400 per turbine.

The demineralized water supplier quoted a cost of $0.0281 per gallon that included ~~the~~ costs for ~~that included~~ exchange~~ costs~~, delivery, and rental fees. The annual cost to meet a NOx concentration limit of 18.8 ppm at 15 percent oxygen on a dry basis is based on the supplier's quote is $82,052 per turbine. ~~An~~The average of the two annual cost estimates is~~of~~ $143,226 per turbine and was used to calculate cost-effectiveness.

The cost-effectiveness was calculated for two~~three~~ emission limits: 18.8 ppm and 5 ppm, at 15 percent oxygen on a dry basis. Table 4-3 summarizes of the cost-effectiveness to require existing turbines to meet each limit.

Table 4-3 – Cost-Effectiveness for Proposed Turbine Emission Limits

Cost-Effectiveness to Meet 18.8 ppm at 15 percent oxygen on a dry basis	
Emission Reductions Over 25 Years[1]	Cost-Effectiveness
138 tons (Facility 1)	$48,600 per ton of NOx reduced
0 tons (Facility 2)	Currently permitted at 18.8 ppm at 15 percent oxygen on a dry basis

[1] Reductions calculated as part of the cost-effectiveness determination are based on current concentration emission levels of the turbines as demonstrated in recent source tests and total 0.015 tpd.

Cost-Effectiveness to Meet 5 ppm at 15 percent oxygen on a dry basis	
Emission Reductions Over 25 Years	Cost-Effectiveness
1492 tons (Facility 1 – turbines without SCR)	$30,200 per ton of NOx reduced
830 tons (Facility 2 – turbines with SCR)	$206,200 per ton of NOx reduced

The cost-effectiveness to meet the proposed NOx BARCT emission limit of 18.8 ppm at 15 percent oxygen on a dry basis is $48,600 per ton of NOx reduced. The average cost-effectiveness to meet the proposed NOx BARCT emission limit of 5 ppm at 15 percent oxygen on a dry basis is $118,200 per ton of NOx reduced.

The proposed emission limits for boilers and turbines are not cost-effective with the exception of the NOx BARCT emission limit of 18.8 ppm at 15 percent oxygen on a dry basis that would apply to turbines. The proposed NOx BARCT emission limit of 18.8 ppm at 15 percent oxygen on a dry basis is proposed to be effective upon the date of adoption. A summary of the cost-effectiveness analysis is in Table 4-4.

Table 4-4 – Cost-Effectiveness Analysis

Category	**TIC ($)**	**AC ($)**	**PWV ($)**	**NOx Reductions tpd**	**CE ($/ton)**
Turbines ≥ 0.3 MW (To meet 18.8 ppm)	N/A	429,800	6.7 MM	0.05	48,600

Permit Revisions

Permits are required to be revised to reflect PR 1179.1 and to remove the references to former source-specific rules that would no longer apply to these sources under Rule 1179.1. Facilities would incur a one-time cost at the time that permit revisions are required, according to the schedule in subdivision (l) of PR 1179.1. The total combined cost for all facility permit revisions is $195,000. Table 4-5 contains the breakdown costs for permit revisions, based on Rule 301 – Permitting and Associated Fees.

Table 4-5 – Permit Revision Costs

Permit Revision Type	Cost (Non-Title V)	Cost (Title V)
Title V permit revision (per facility)	N/A	$1,518.26
Change of Conditions (per engine)	$4319.40	$5,412.63
Administrative Change (per equipment)	$962.75	$1,206.41
I&M Plan (per applicable facility w/engines)	$725.60	$909.25

Total Cost-Effectiveness of PR 1179.1

The cost-effectiveness to implement PR 1179.1 is $50,054 per ton of NOx reduced. Costs include the cost for three turbines at one facility to meet 18.8 ppm and all facilities with equipment permits that reference other source-specific rules, to revise equipment permits to reflect PR 1179.1.

SOCIOECONOMIC ASSESSMENT

California Health & Safety Code §40440.8 requires a socioeconomic impact assessment for proposed and amended rules resulting in significant impacts to air quality or emission limitations. This assessment shall include affected industries, range of probable costs, cost effectiveness of control alternatives, and emission reduction potential.

During the rulemaking for the December 2018 amendments for Rule 1146 Series, staff recommended to separate provisions for combustion equipment at Publicly Owned Treatment Works Facilities (POTWs). Proposed Rule 1179.1 - ~~NOx~~ Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities (PR 1179.1) was developed to establish BARCT requirements for combustion equipment located at POTWs using digester gas.

Proposed Rule 1179.1 would affect 30 POTW facilities with a total of eighty-six biogas fueled boilers, turbines, and engines. These facilities belong to the North American Industrial Classification Codes (NAICS) 2213 (Water, Sewage, and Other Systems) and 5622 (Waste

Treatment and Disposal). Out of these 30 facilities, six are located in Los Angeles County, seven each in Orange and San Bernardino counties, and 10 in Riverside County.

Proposed Rule 1179.1 applies to combustion equipment used at POTWs. Specifically, PR 1179.1 contains emission limits on boilers, turbines, and engines at POTWs. Many of the emissions limits within PR 1179.1 are consistent with limits set in existing source specific rules (e.g., Rule 1146 and 1110.2) or equipment permits, and the boilers, engines, and turbines at POTWs already meet those limits. However, PR 1179.1 will require turbines greater than or equal to 0.3 MW to meet new, lower emission limits.

Of the 86 biogas-fueled boilers, turbines, and engines affected by PR 1179.1, only three turbines at one facility are expected to incur additional compliance costs associated with the PR 1179.1 requirements. Compliance costs for the three turbines above 0.3 MW are expected due to increased water injection and are estimated at $429,600 ($143,200 per turbine) annually.[5] In addition, facilities will incur a one-time cost to reconcile permits and comply with the PR 1179.1 requirements. The total estimated one-time cost for all facility permit revisions is estimated at $195,000,[6] and accounts for both Title V and non-Title V equipment permit revisions. The annualized cost of these permit revisions at four percent real interest rate is estimated at $23,985. As such, the estimated total annual compliance cost from PR 1179.1 is estimated at $453,585.

The proposed NOx emission limit of 18.8 ppm at 15 percent oxygen on a dry basis for turbines greater than or equal to 0.3 MW will reduce NOx emissions by 0.015 tpd. All other equipment will continue to comply with current emission limits. The cost-effectiveness of PR 1179.1, including the permit revisions, is estimated at $50,000 per ton of NOx reduced based on current concentration emission levels of the turbines as demonstrated in recent source tests.

The estimated total annual compliance costs from PR 1179.1 ($453,585) is estimated to be less than one million dollars annually. It has been a standard practice for South Coast AQMD's socioeconomic impact assessments that, when the annual compliance cost is less than one million current U.S. dollars annually, the Regional Economic Models Inc. (REMI)'s Policy Insight Plus Model is not used to simulate jobs and macroeconomic impacts, as is the case here. This is because the resultant impacts would be too small relative to the baseline regional economy to reliably determine any impacts from the modeling analysis.

[5] The cost figure of $143,200 was calculated using an average of two estimates provided by the facility affected by PR 1179.1 limits and a cost estimate provided by a demineralized water supplier.

[6] Title V facilities have a Title V revision cost of $1,518.26 (per facility). Each piece of permitted equipment at Title V facilities requiring a Change of Conditions permit revision will cost $5,412.63. Each piece of permitted equipment at non-Title V facilities requiring a Change of Conditions permit revision will cost $4,319.40. Facilities with permitted equipment requiring an Inspection & Monitoring plan will cost $909.25 per Title V facility and $725.60 per non-Title V facility. All other equipment requires an Administrative Change permit revision at a cost of $1,206.41 per piece of equipment at Title V facilities and $962.75 per piece of equipment at non-Title V facilities.

CALIFORNIA ENVIRONMENTAL QUALITY ACT ASSESSMENT

PR 1179.1 is 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 15070, the South Coast AQMD has prepared an Environmental Assessment (EA) with less than significant impacts for PR 1179.1, which is a substitute CEQA document, prepared in lieu of a Negative Declaration. A Draft EA was~~has been~~ released for a 30-day public comment and review period from August 12, 2020 to September 11, 2020. ~~If comments are~~One comment letter was submitted;~~,~~ the letter~~s~~ and responses to comments were~~will be~~ incorporated into the Final EA which has been~~will be~~ included as an attachment to the Governing Board package. Prior to making a decision on the adoption of PR 1179.1, the South Coast AQMD Governing Board must review and certify the Final EA, including responses to comments, as providing adequate information on the potential adverse environmental impacts that may occur as a result of adopting PR 1179.1.

DRAFT FINDINGS UNDER CALIFORNIA HEALTH AND SAFETY CODE SECTION 40727

Requirements to Make Draft Findings
California Health and Safety Code Section (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.

Necessity
PR 1179.1 is needed to establish NOx, CO, and/or VOC emission limits for digester gas and/or natural gas fired boilers, turbines, and engines located at publicly owned treatment works (POTWs) that are representative of BARCT, as well as monitoring, reporting, and recordkeeping requirements.

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.

Clarity
PR 1179.1 is written or displayed so that its meaning can be easily understood by the persons directly affected by it.

Consistency
PR 1179.1 is in harmony with and not in conflict with or contradictory to, existing statutes, court decisions or state or federal regulations.

Non-Duplication
PR 1179.1 will not impose the same requirements as any existing state or federal regulations. The proposed amended rules are necessary and proper to execute the powers and duties granted to, and imposed upon, the South Coast AQMD.

Reference
In amending these rules, the following statutes which the South Coast AQMD hereby implements, interprets or makes specific are referenced: H&SC Sections 39002, 40001, 40702, 40440(a), 40440(b), 40406, and 40725 through 40728.5.

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 requirements, existing rules from other air quality management districts and/or air pollution control districts, and existing or proposed SCAQMD rules and air pollution control requirements and guidelines which are applicable to natural gas and/or digester gas fired turbines. See Table 4-6 below.

Table 4-6: PR 1179.1 Comparative Analysis- Turbines

Rule Element	PR 1179.1	BAAQMD Regulation 9 Rule 9	SMAQMD Rule 413	SJVAPCD Rule 4703	40 CFR Part 60 Subpart GG	40 CFR Part 60 Subpart KKKK
Applicability	Located at a POTW facility: Digester gas and dual fuel turbines < 0.3 MW and turbines ≥ 0.3 MW..	Stationary gas turbines with a heat input rating ≥ 5 MMBtu/hr	Stationary gas turbines with ratings equal to or greater than 0.3 megawatt (MW) output, or 3 MMBTU/hr input and operated on gaseous and/or liquid fuel.	Stationary gas turbines with ratings equal to or greater than 0.3 megawatt (MW) or a maximum heat input rating of more than 3,000,000 Btu per hour.	Gas turbines with heat input of ≥ 10 MMBtu/hr that commenced construction, modification or re-construction 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
Requirements	NOx emission limits @ 15% O_2: • ≥ 0.3 MW firing 60% digester gas or more – 18.8 ppm on or before date of adoption • Simple cycle ≥ 0.3 MW firing	General NOx emission limits (@ 15% O_2) for refinery fuel gas, waste gas or LPG: • < 5 MMBtu/hr-Exempt • 5 – 50 MMBtu/hr – 2.53 lbs/MWhr or 50 ppmv • > 50 – 150 MMBtu/hr – 2.34 lbs/MWhr or 50 ppmv	NOx emission limits (@ 15% O_2) for gaseous fuel: • ≥ 0.3 to < 2.9 MW – 42 ppmv • ≥ 2.9 MW (operating < 877 hr/yr) – 42 ppmv • ≥ 2.9 to < 10 MW (operating ≥	NOx emission limits (@ 15% O_2) for gas fuel: • < 3 MW – 9 ppmvd • 3 – 10 MW pipeline gas turbine – 8 ppmvd during steady state and 12 ppmvd during non-steady state	NOx limit @ 15% O_2, where Y = Manufacture's rated heat input and F = NOx emission allowance for fuel-bound nitrogen: • $0.0075*(14.4/Y)+F$ • $0.0150*(14.4/Y)+F$	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

	100%natural gas- 2.5 ppm on or before date of adoption • Combined cycle ≥ 0.3 MW firing 100% % natural gas- 2 ppm on or before date of adoption • < 0.3 MW gas- 9 ppm on or before date of adoption CO emission limit @15% O_2: 130 ppm	• > 150 – 250 MMBtu/hr – 0.70 lbs/MWhr or 15 ppmv • > 250 – 500 MMBtu/hr – 0.43 lbs/MWhr or 9 ppmv • > 500 MMBtu/hr – 0.26 lbs/MWhr or 9 ppmv General NOx emission limits (@ 15% O_2) for natural gas: • < 5 MMBtu/hr- Exempt • 5 – 50 MMBtu/hr - 2.12 lbs/MWhr or 42 ppmv • > 50 – 150 MMBtu/hr (no retrofit available) – 1.97 lbs/MWhr or 42 ppmv • > 50 – 150 MMBtu/hr (WI/SI enhancement available) – 1.64 lbs/MWhr or 35 ppmv • > 50 – 150 MMBtu/hr (DLN technology available) – 1.17 lbs/MWhr or 25 ppmv • > 150 – 250 MMBtu/hr – 0.70 lbs/MWhr or 15 ppmv • > 250 – 500 MMBtu/hr – 0.43 lbs/MWhr or 9 ppmv • > 500 MMBtu/hr – 0.15 lbs/MWhr or 5 ppmv Low usage NOx emission limits (@ 15% O_2) for refinery fuel gas, waste gas or LPG: • < 50 MMBtu/hr – exempt • 50 - > 500 MMBtu/hr – N/A	877 hr/yr) – 25 ppmv • ≥ 10 MW (no SCR, operating ≥ 877 hr/yr) – 15 ppmv • ≥ 10 MW (with SCR, operating ≥ 877 hr/yr) – 9 ppmv	• 3 – 10 MW (operating < 877 hrs/yr, not listed above) – 9 ppmvd • 3 – 10 MW (operating ≥ 877 hrs/yr, not listed above) – 5 ppmvd • > 10 MW (simple cycle, operating < 200 hrs/yr, except as provided in Section 5.1.3.3) – 25 ppmvd • > 10 MW (simple cycle, operating >200 but no greater than 877 hrs/yr) – 5 ppmvd CO emission limits @15% O_2: • Units not identified below – 200 ppmv • General Electric Frame 7 – 25 ppmv • General Electric Frame 7 with Quiet Combustors – 52 ppmv • < 2 MW Solar Saturn gas turbine powering centrifugal compressor – 250 ppmv	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 – 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

		Low usage NOx emission limits (@ 15% O_2) for natural gas: • < 50 MMBtu/hr – exempt • 50 – 250 MMBtu/hr – 1.97 lbs/MWhr or 42 ppmv • > 250 – 500 MMBtu/hr – 1.17 lbs/MWhr or 25 ppmv • > 500 MMBtu/hr – 0.72 lbs/MWhr or 25 ppmv				• > 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
Reporting	Source testing. CEMS data every six months (Rule 218).	Source testing	None	Source testing	Semi- annual reports of excess emissions and monitor downtime	Semi- annual reports of excess emissions and monitor downtime. Annual performance test results.
Monitoring	A continuous in-stack NOx monitor for turbines with a capacity of 2.9 MW or greater. Periodic source testing for all turbines.	A continuous in-stack NOx monitor for turbines with a heat input rating equal to or greater than 150 MMBtu/hr and operate for more than 4000 hours in any 36-month period. Source test at least once per calendar year, not to exceed 15 months, for turbines that operate more than 400 hours in any 12-month period and is not equipped with a continuous monitor. Source test every two calendar years, not to exceed 25 months, for turbines that operate 400 hours or less in any 12 month period.	Equipment which monitors control system operating parameters, elapsed time of operation, and continuous exhaust gas NOx concentration s for turbines with a rated output ≥ 10 MW and operated for more than 4000 hours in any one calendar year during the three years before April 6, 1995. Equipment which monitors control	Continuous emissions monitoring equipment for NOx and CO or monitoring of operational characteristics recommended by the turbine manufacturer of emission control system supplier. Exhaust gas NOx emissions monitoring system for turbines 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994. Annual	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. Monitor the total sulfur content of the fuel being fired.	A continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel or continuous emission monitoring for stationary gas turbines using water or steam injection. Annual performance tests or continuous monitoring for turbines without water or steam injection. Monitor the total sulfur content of the fuel being fired.

			system operating parameters and elapsed time of operation for turbines with a rated output < 10 MW. Annual source testing.	source testing except for turbines operated < 877 hrs/yr, which are to be source tested biennially.		
Recordkeeping	Maintain and keep records of CEMS data, source test reports, diagnostic emission checks, operating hours, maintenance, service, and tuning for five years.	Daily operating log for low-usage exemption maintained for two years. Records of fuel consumption, output, and flow rates if using NOx limits expressed in lbs/MWhr.	Permit number, manufacturer, model, rating in MW, actual startup and shutdown time, daily hours of operation, cumulative hours of operation to date for the calendar year, actual daily fuel usage, emission test results, and maintenance records for two years. Additional records of exemptions.	Operating log, start-up and shutdown records, records of each bypass transition period and primary re-ignition period maintained for five years	Performance testing; emission rates; monitoring data; CEMS audits and checks	Performance testing; emission rates; monitoring data; CEMS audits and checks
Fuel Restrictions	Liquid fuel	None	None	None	None	None

INCREMENTAL COST-EFFECTIVENESS

Health and Safety Code section 40920.6 requires an incremental cost-effectiveness analysis for Best Available Retrofit Control Technology (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 options as compared to the next less expensive control option.

Incremental cost-effectiveness is calculated as follows:

$$\text{Incremental cost-effectiveness} = (C_{alt} – C_{proposed}) / (E_{alt} – E_{proposed})$$

Where:
$C_{proposed}$ is the present worth value of the proposed control option;
$E_{proposed}$ are the emission reductions of the proposed control option;
C_{alt} is the present worth value of the alternative control option; and
E_{alt} are the emission reductions of the alternative control option

The proposed project would require one facility to meet 18.8 ppm at 15 percent oxygen on a dry basis on three turbines. The next progressively more stringent potential control option would be to require turbines to meet 5 ppm at 15 percent oxygen on a dry basis and would affect two facilities and a total of six turbines. To meet 5 ppm, one facility would be required to implement SCR on their existing turbines. The other facility would be required to replace their turbines with lower emitting turbines to meet 5 ppm.

Incremental cost-effectiveness = ($160,832,987 – $6,712,430) / (1,791 – 138) =
$93,237 per ton of NOx reduced

The incremental cost analysis presented above demonstrates that the alternative control option is not viable when compared to the control strategy of the proposed amendments.

APPENDIX A – LIST OF AFFECTED FACILITIES

Table A-1: Facilities Affected by PR 1179.1

ID	Facility Name
20252	Banning City Wastewater Treatment Plant
2537	Corona City Department of Water & Power
7417	Eastern Municipal Water District
19159	Eastern Municipal Water District
1703	Eastern Municipal Water District
13088	Eastern Municipal Water District
9163	Inland Empire Utilities Agency
1179	Inland Empire Utilities Agency
147371	Inland Empire Utilities Agency
3513	Irvine Ranch Water District
800214	LA City Sanitation Bureau
10245	LA City Terminal Island Treatment Plant
800236	LA County Sanitation District
22674	LA County Sanitation District
94009	Las Virgenes Municipal Water District
17301	Orange County Sanitation District
29110	Orange County Sanitation District
5756	Redlands City Wastewater Treatment Plant
12923	Rialto City
9961	Riverside City Water Quality Control
11301	San Bernardino Municipal Water Department San Clemente City
20237	San Clemente City
51304	Santa Margarita Water District
181040	Santa Margarita Water District
13433	South Orange County Wastewater Authority
3966	South Orange County Wastewater Authority
10198	Valley Sanitation District
118526	Western Municipal Water District
111176	Western Riverside County Regional Wastewater Authority Treatment Plant
50402	Yucaipa Valley Water District

APPENDIX B – RESPONSES TO PUBLIC COMMENTS

Comment: PR 1179.1 should include a definition for "thermal stabilization period" and allow 2 hours for this period during startup, for cogeneration and combined cycle turbines.

Response: Staff included a 3-hour startup period for turbines ≥ 0.3 MW without SCR to allow sufficient time for the thermal stabilization period and/or any other startup mechanisms required for the turbine to reach stable conditions.

Comment: PR 1179.1 needs to specify how 40% natural gas is defined for the turbine emission limits.

Response: Staff revised the 18.8 ppm at 15% oxygen on a dry basis turbine emission limit to apply to any turbine ≥ 0.3 MW firing at least 60% digester gas. The rule specifies that 60% digester gas is based on volume averaged over a 24-hour period.

Comment: Turbines cannot meet natural gas emission limits when firing digester gas and more than 40% percent natural gas. Rule should have a weighted emission limit for turbines ≥ 0.3 MW firing less than 60% digester gas (more than 40% natural gas).

Response: Staff has included a provision for a weighted emission limit for turbines ≥ 0.3 MW firing more than 40% natural gas and less than 100% natural gas. Turbines firing 100% natural gas would be required to meet the natural gas NOx emission limit.

Comment: It is unclear what emission limits in Rules 1146 and 1146.1 dual fuel boilers are subject to when firing 100% natural gas.

Response: Staff has included dual fuel boilers that can fire 100% natural gas in the applicability of PR 1179.1. The emission limits for dual fuel boilers are contained in Table 1 and include the emission limit when firing 100% natural gas.

Comment: Throughout district rules, it is not clearly communicated that different rules and programs have different source test requirements.

Response: Source test requirements contained in PR 1179.1 are specific to PR 1179.1. Source test requirements contained in other rules and programs apply to the specific rule or program in which the requirements are contained. Facilities are required to meet all applicable requirements in across all applicable rules and programs.

Comment: PR 1179.1 does not include a provision currently in 1110.2 that allows a facility with engines at the same location with a combined output capacity rating of 1500 bhp or greater and a combined fuel usage of > 16 x 10^9 Btu per year (higher heating value) to comply with I&M plan requirements in lieu of installing a CEMS.

Response: Staff has included this provision to reflect the language currently in Rule 1110.2.

Comment: PR 1179.1 language pertaining to source test protocol submittal requirements does not clearly state when a subsequent source test protocol is required to be submitted for approval.

Response: Staff revised the rule language to clearly state when a subsequent source test protocol would be required for units subject to a previously approved protocol. Subsequent source test protocols would only be required if the unit has been altered in a manner that requires a permit alteration, if emission limits for the unit have changed since the previous source test, or if a new protocol is requested by the Executive Officer.

Comment: PR 1179.1 should allow Title V permit revisions to occur on the same cycle as Title V permit renewals.

Response: Staff has included a schedule for permit revisions that allows for Title V permit revisions to occur on the same cycle as Title V permit renewals.

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Environmental Assessment for Proposed Rule 1179.1 – Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities

September 2020

State Clearinghouse Number: 2020080171
South Coast AQMD Number: 08122020KR

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PREFACE

This document constitutes the Final Environmental Assessment (EA) for Proposed Rule 1179.1 – Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities. A Draft EA was circulated for a 30-day public review and comment period from August 12, 2020 to September 11, 2020 and one comment letter was received. The comment letter and response relative to the Draft EA have been included in Appendix D of this Final EA.

Analysis of PR 1179.1 in the Draft EA indicated that reducing NOx emissions is a direct environmental benefit, and furthermore, no secondary significant adverse environmental impacts were expected for any environmental topic areas. Since no significant adverse impacts were identified, an alternatives analysis and mitigation measures are not required. [CEQA Guidelines Section 15252].

To facilitate identification of the changes between the Draft EA and the Final EA, modifications to the document were included as <u>underlined text</u> and text removed from the document was indicated by ~~strikethrough~~. Subsequent to the release of the Draft EA for public review and comment, modifications were made to PR 1179.1 and some of the revisions were made in response to verbal and written comments received during the rule development process. The modifications include: 1) rewording rule title language and 2) including other minor edits and clarifications. To avoid confusion, minor formatting changes are not shown in underline or strikethrough mode.

South Coast AQMD staff has reviewed the modifications to PR 1179.1 after the release of the Draft EA for the 30-day public review and comment period, updated the CEQA analysis accordingly and concluded that none of the revisions: 1) constitute significant new information; 2) constitute a substantial increase in the severity of an environmental impact; or, 3) provide new information of substantial importance relative to the Draft EA. In addition, revisions to the proposed project 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 EA pursuant to CEQA Guidelines Sections 15073.5 and 15088.5. Therefore, the Draft EA has been revised to include the aforementioned modifications such that is now the Final EA for PR 1179.1.

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CHAPTER 1

PROJECT DESCRIPTION

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 emission control rules and regulations in the South Coast Air Basin (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 (SO2), 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.

During the rulemaking for the December 2018 amendments for Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process

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

Heaters (Rule 1146), Rule 1146.1 – Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters (Rule 1146.1), and Rule 1146.2 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters (Rule 1146.2), the South Coast AQMD received comments describing unique challenges faced by operators of publicly owned treatment works (POTW) facilities that treat municipal wastewater, especially regarding the combustion of digester gas or digester gas blends and the manner in which POTWs provide essential public services. In addition, Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines (Rule 1134) previously contained emission limits for all fuels combusted in turbines that were in operation at POTWs prior to 1989. Further, NOx, VOC, and CO emissions from engines combusting all gaseous and liquid fuels, including digester gas, are regulated by Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines (Rule 1110.2). To streamline and update the multiple rule requirements applicable to POTWs, South Coast AQMD recommended developing a separate rule to specifically address combustion equipment operating at POTWs. As such, Proposed Rule (PR) 1179.1 ~~– NOx~~ Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities was developed to establish Best Available Retrofit Control Technology (BARCT) requirements for combustion equipment operated at POTWs and to consolidate and migrate applicable requirements from Rules 1146, 1146.1 and 1146.2, Rule 1134, and 1110.2.

Specifically, PR 1179.1 is designed to reduce emissions of: 1) NOx and CO from boilers, steam generators and process heaters rated greater than 400,000 British thermal units (Btu) per hour and fueled by digester gas or a digester gas blend; 2) NOx and CO from turbines rated less than 0.3 megawatt (MW) fueled by digester gas or a digester gas blend; 3) NOx and CO from turbines rated at greater than or equal to 0.3 MW fueled by natural gas, digester gas, or a digester gas blend; and 4) NOx, CO and VOC from engines rated at greater than 50 brake horsepower (bhp) fueled by digester gas or a digester gas blend. In addition, PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. PR 1179.1 is estimated to reduce up to 0.05 ton per day of NOx emissions.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

The California Environmental Quality Act (CEQA), California Public Resources Code Section 21000 *et seq.*, requires environmental impacts of proposed projects to be evaluated and feasible methods to reduce, avoid or eliminate significant adverse impacts of these projects to be identified and implemented. The lead agency is the "public agency that has the principal responsibility for carrying out or approving a project that may have a significant effect upon the environment." [Public Resources Code Section 21067]. Since PR 1179.1 is a South Coast AQMD-proposed rule, the South Coast AQMD has the primary responsibility for supervising or approving the entire project as a whole and is the most appropriate public agency to act as lead agency. [CEQA Guidelines[6] Section 15051(b)].

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 lead agency, responsible agencies, decision makers and the general public of potential adverse environmental

[6] The CEQA Guidelines are codified at Title 14 California Code of Regulations Section 15000 *et seq.*

impacts that could result from implementing PR 1179.1 (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 an environmental impact report once the Secretary of the Resources Agency has certified the regulatory program. The South Coast AQMD's regulatory program was certified by the Secretary of Resources Agency on March 1, 1989 per CEQA Guidelines Section 15251(l), and has been adopted as South Coast AQMD Rule 110 – Rule Adoption Procedures to Assure Protection and Enhancement of the Environment.

Because PR 1179.1 requires discretionary approval by a public agency, it is a "project" as defined by CEQA[7]. The proposed project will reduce NOx, CO, and VOC emissions for engines; and NOx and CO emissions for boilers and turbines located at POTWs; and will provide an overall environmental benefit to air quality. However, South Coast AQMD's review of the proposed project also shows that the activities that facility operators may undertake to comply with PR 1179.1 may also create secondary adverse environmental impacts that would not result in significant impacts for any environmental topic area. Thus, the analysis of PR 1179.1 indicates that the type of CEQA document appropriate for the proposed project is an Environmental Assessment (EA). The EA is a substitute CEQA document, which the South Coast AQMD, as lead agency for the proposed project, prepared in lieu of a Negative Declaration with no significant impacts (CEQA Guidelines Section 15252), pursuant to the South Coast AQMD's Certified Regulatory Program (Public Resources Code Section 21080.5, CEQA Guidelines Section 15251(l); South Coast AQMD Rule 110). The EA 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.

The Draft EA included~~s~~ a project description in Chapter 1 and an Environmental Checklist in Chapter 2. The Environmental Checklist provides a standard tool to identify and evaluate a project's adverse environmental impacts and the analysis concluded that no significant adverse impacts would be expected to occur if PR 1179.1 is implemented. Because PR 1179.1 will have no statewide, regional or areawide significance, no CEQA scoping meeting is required to be held for the proposed project pursuant to Public Resources Code Section 21083.9(a)(2). Further, pursuant to CEQA Guidelines Section 15252, since no significant adverse impacts were identified, no alternatives or mitigation measures are required.

The Draft EA was ~~is being~~ released for a 30-day public review and comment period from August 12, 2020 to September 11, 2020. One ~~All~~ comment~~s~~ letter was received during the public comment period on the analysis presented in the Draft EA; the comment letter and ~~will be~~ response~~ded to and~~ is included in ~~an~~ Appendix D of this ~~to the~~ Final EA.

Subsequent to the release of the Draft EA for public review and comment, modifications were made to PR 1179.1 and some of the revisions were made in response to verbal and written comments received during the rule development process. South Coast AQMD staff has reviewed the modifications to PR 1179.1 after the release of the Draft EA for the 30-day public review and comment period, updated the CEQA analysis accordingly and concluded that none of the revisions:

[7] CEQA Guidelines Section 15378

1) constitute significant new information; 2) constitute a substantial increase in the severity of an environmental impact; or, 3) provide new information of substantial importance relative to the Draft EA. In addition, revisions to the proposed project 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 EA pursuant to CEQA Guidelines Sections 15073.5 and 15088.5. Therefore, the Draft EA has been revised to include the aforementioned modifications such that is now the Final EA for PR 1179.1.

Prior to making a decision on the adoption of PR 1179.1, the South Coast AQMD Governing Board must review and certify the Final EA as providing adequate information on the potential adverse environmental impacts that may occur as a result of adopting PR 1179.1.

PROJECT LOCATION

PR 1179.1 applies to certain combustion equipment (e.g., boilers, steam generators, process heaters, turbines, and engines) operated at POTWs located within the South Coast AQMD jurisdiction which covers an area of approximately 10,743 square miles, consisting of the four-county South Coast Air Basin (Basin) as defined in the California Code of Regulations, Title 17, Section 60104, and the non Palo Verde, Riverside County portion~~s~~ of the ~~Salton Sea Air Basin (SSAB) and~~ Mojave Desert Air Basin (MDAB). The Basin, which is a subarea of South Coast AQMD's jurisdiction, is bounded by the Pacific Ocean to the west and the San Gabriel, San Bernardino, and San Jacinto mountains to the north and east. It 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 1-1).

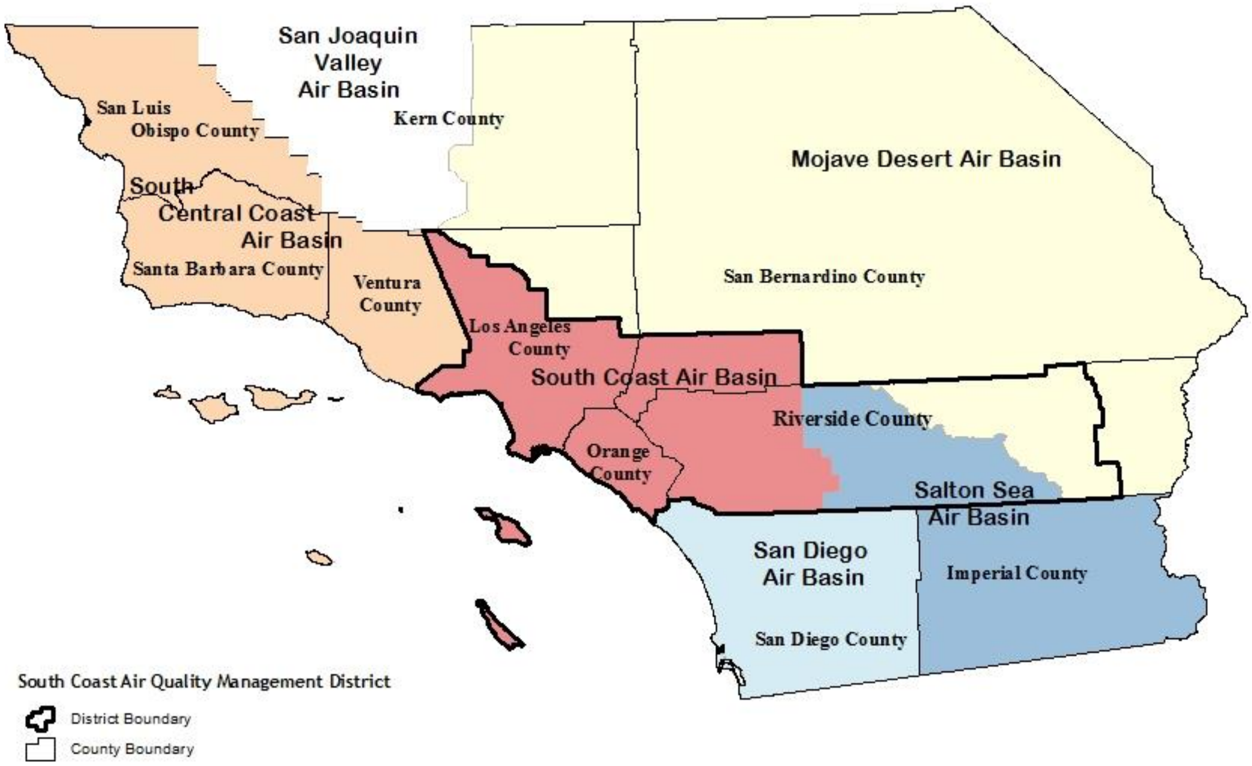


Figure 1-1
Southern California Air Basins

PROJECT BACKGROUND

POTWs, also known as wastewater treatment or reclamation plants, process and treat municipal wastewater and sewage, and are either owned or operated by a public entity. POTWs treat sewage and wastewater via a multi-stage process before discharging treated water from the facility. The multi-staged treatment process involves anaerobic digestion during which micro-organisms decompose organic solids in the absence of oxygen to produce a by-product, referred to as digester gas or biogas, which can be used as a viable source of fuel. Digester gas is typically utilized by combustion equipment to provide heat or power for multiple processes at the POTW. In the event excess digester gas is produced at the POTW and equipment that ordinarily utilizes digester gas is either operating at its maximum capacity or is otherwise unavailable, the excess digester gas is routed to and combusted in a flare. Due to a potential cost savings, utilizing digester gas that is produced on-site as a fuel source for combustion equipment is considered a beneficial use and is preferred over flaring, especially if relying on purchased natural gas provided by a local a utility to provide fuel for POTW combustion equipment could potentially be avoided.

Combustion equipment operated at POTWs include boilers, steam generators, process heaters, engines and turbines which are currently regulated by source-specific South Coast AQMD rules or by permit conditions. For example, NOx and CO emissions from the combustion of all fuel types, including digester gas, in boilers, process heaters and steam generators are regulated by Rules 1146 and 1146.1.

In addition, Rule 1134 previously contained emission limits for all fuels combusted in turbines that were in operation at POTWs prior to 1989. However, while there are six turbines currently operated at POTWs, none were operating prior to 1989. Rule 1134 was amended on April 5, 2019 to specifically exclude turbines located at POTWs because PR 1179.1 was undergoing rule development. Also, NOx, VOC, and CO emissions from engines combusting all gaseous and liquid fuels, including digester gas, are regulated by Rule 1110.2.

During the rule development for the December 2018 amendments to Rules 1146, 1146.1, and 1146.2, the South Coast AQMD received comments describing unique challenges faced by POTW operators that treat municipal wastewater, especially regarding the combustion of digester gas and the manner in which POTWs provide essential public services. In response to these comments, South Coast AQMD recommended developing a separate rule to specifically address combustion equipment operating at POTWs. As such, PR 1179.1 was developed to establish BARCT requirements for combustion equipment operated at POTWs and to consolidate and migrate applicable requirements from Rules 1146, 1146.1 and 1146.2, Rule 1134, and Rule 1110.2. Specifically, PR 1179.1 is designed to reduce emissions of: 1) NOx and CO from boilers, steam generators and process heaters rated greater than 400,000 Btu per hour and fueled by digester gas or a digester gas blend; 2) NOx and CO from turbines rated less than 0.3 MW fueled by digester gas or a digester gas blend; 3) NOx and CO from turbines rated at greater than or equal to 0.3 MW fueled by natural gas, digester gas, or a digester gas blend; and 4) NOx, CO and VOC from engines rated at greater than 50 bhp fueled by digester gas or a digester gas blend. In addition, PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. PR 1179.1 is estimated to reduce up to 0.05 ton per day of NOx emissions.

TECHNOLOGY OVERVIEW

Combustion is a high temperature chemical reaction resulting from burning a gas, liquid, or solid fuel (e.g., natural gas, digester 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. An ideal combustion reaction is when the entire amount of fuel needed is completely combusted in the presence of air so that only carbon dioxide (CO2) and water are produced as by-products. However, since fuel contains other components such as nitrogen and sulfur and the amount of air mixed with the fuel can vary, in practice, fuel is not completely combusted whereby smog-forming by-products such as NOx, oxides of sulfur (SOx), CO, and soot (solid carbon) are produced and discharged into the atmosphere.

Of the total NOx emissions that can be generated during combustion, there are two types of NOx formed: 1) thermal NOx; and 2) fuel NOx. Thermal NOx is produced from the reaction between the nitrogen and oxygen from air in the combustion chamber at high temperatures while fuel NOx is formed during the reaction between the nitrogen contained in the fuel and the available oxygen from air in the combustion chamber. The amount of fuel NOx generated is dependent on fuel type and not the equipment per se; boilers, steam generators, process heaters, engines, and gas turbines all generate thermal NOx during combustion.

The following describes the various types of existing combustion equipment that may be affected by PR 1179.1 and the type of NOx emission control techniques that are typically employed.

Boilers, Steam Generators and Process Heaters

Boilers and steam generators use energy from a fuel source to heat water into steam which is then directed for usable work. There are two main types of boilers: water-tube and fire-tube. Water-tube boilers circulate water through a series of tubes, the tubes are heated externally by the combustion gas, and the surrounding hot gases heat the water in the steam-generating tubes. Fire-tube boilers pass combustion gases inside a series of tubes that are surrounded by a closed vessel of water that is heated to produce steam. Process heaters use liquid or gaseous fuel (including landfill and digester gas) and/or solid fossil fuel to transfer heat from the combustion gases to water or process streams.

NOx emissions from boilers fitted with low NOx burners typically minimize the amount of NOx emissions generated during combustion. Low NOx burners differ from traditional burners by controlling the fuel-to-air mixing ratio in the combustion chamber at each burner in order to lower the peak flame temperature and reduce the amount of NOx created. All boilers that use digester gas as a fuel currently have South Coast AQMD permits. In addition, Rules 1146 and 1146.1 require that boilers rated greater than two million Btu per hour are required to achieve a NOx emission limit of either 15 ppm (corrected to three percent oxygen on a dry basis) when fueled by digester gas or 9 ppm (corrected to three percent oxygen on a dry basis) when fueled by natural gas. All the existing boilers subject to PR 1179.1 have South Coast AQMD Permits to Operate which contain the applicable NOx emission limits, so no physical modifications to the boilers are expected to be necessary in order to comply with the requirements in PR 1179.1.

Turbines

Gas turbines combust either gaseous fuel (e.g., natural gas, digester gas or a blend) or liquid fuel (e.g., diesel) to produce electricity. Turbines can be used in combined-cycle and simple-cycle arrangements. Combined-cycle turbines are cogeneration units designed to generate electricity and heat at the same time as they are able to recover heat from the exhaust to heat up water or to produce steam. Combined-cycle turbines are typically used for very large systems such as POTWs. Simple-cycle gas turbines produce electricity but do not recover heat from the exhaust. Controlling NOx emissions from turbines can be accomplished pre-combustion with lean pre-mix emission combustors (dry-low NOx) or injecting water or steam in the combustion chamber of the turbine. Controlling NOx emissions post-combustion can be accomplished with selective catalytic reduction (SCR) technology and requires a fuel gas treatment system to remove contaminants from gas streams prior to combustion. Newly manufactured turbines available on the market are capable of achieving low NOx emission levels without the need for post-combustion control technology such as SCR. The following provides a brief summary of each of these NOx control methods:

Fuel Gas Treatment

Fuel Gas Treatment can be employed to remove undesirable compounds from gaseous fuel supplies prior to combustion. For example, digester gas, contains contaminants such as siloxanes and sulfur compounds such as hydrogen sulfide (H2S), which, if combusted, can cause mechanical problems in the equipment, limit the effectiveness of other NOx control equipment, as well as produce contaminants in the exhaust stream. The following three types of fuel gas treatment approaches can be utilized for removing contaminants in the fuel gas and can be applied individually or in combination: consumable media, regenerative media and chiller/adsorption refrigeration.

The effectiveness of contaminant removal depends on the contaminants in the fuel and the selection of media appropriate for the contaminants. The three most common types of media that are used in the South Coast AQMD at POTWs are activated carbon, molecular sieves, and silica gel. Activated carbon is a versatile adsorbent because it is highly porous, suitable to adsorb organic contaminants. A molecular sieve has pores of uniform size and is capable of performing selective removal of contaminants at low concentrations. Silica gel is a shapeless and porous adsorbent that has a greater capacity than activated carbon to adsorb siloxanes and has a high affinity for water that aids in moisture removal.

Consumable media systems are commonly used with activated carbon. This type of removal system requires saturated media to be changed out with fresh media.

Regenerative media systems are commonly used with molecular sieve, silica gel, clay and zeolite. These systems consist of at least two media canisters. One canister filled with fresh media processes the gaseous fuel while the other canister regenerates the spent media by purging with hot air. Regenerative media types require smaller canisters and less quantities of media when compared to consumable media systems. Regenerative media function can be enhanced by applying polymeric resins which increase service life, increase adsorbent capacity, and remove contaminants quicker and at a lower temperature during the regeneration process.

Chiller/adsorption refrigeration is capable of removing contaminants by reducing the temperature of the gaseous fuel such as digester gas to remove moisture and contaminants via condensation. Chiller/adsorption refrigeration can also be used in combination with consumable media whereby the consumable media step serves as a polishing stage to remove trace amounts of siloxanes or other contaminants. Wastewater treatment facilities have reported 50 percent removal efficiency of siloxanes and 32 percent long-term removal efficiency of siloxanes, via chiller/adsorption refrigeration.

Lean Pre-mixed Combustion or Dry Low Emissions
Prior to combustion, gaseous fuel and compressed air are pre-mixed, minimizing localized hot spots or spikes that produce elevated combustion temperatures and in turn, minimize the formation of NOx. Atmospheric nitrogen from the combustion air is mixed with additional excess air upstream of the combustor at deliberately fuel-lean conditions. By supplying approximately twice as much air as what is actually needed to burn the limited amount of fuel in the combustion chamber, the amount of NOx that can be formed is limited since very lean fuel conditions cannot produce the high temperatures that create thermal NOx. By utilizing this technology, NOx emissions have been demonstrated at less than nine parts per million by volume (ppmv), corrected to 15% oxygen, dry basis. The technology is engineered into the combustor as an intrinsic part of the turbine design. Fuel staging or air staging is utilized to keep the flame within its operating temperature range. It is not available as a "retrofit" technology and must be designed for each turbine application.

Water or Steam Injection
Water or steam injection is when demineralized water is injected into the combustor through the fuel nozzles to cool the flame temperature and thereby, reduce the amount of NOx produced. For example, NOx emission levels from natural gas turbines can be reduced via water or steam injection by 80%, corrected to 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 or steam increases CO emissions. and there is added cost to demineralize the water. Turbines using water or steam injection have increased maintenance due to erosion and wear.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) technology is widely used for gas turbines as the primary post-combustion approach for achieving additional NOx reductions because it is capable of reducing NOx emissions from the turbine exhaust by 90 to 95 percent.

With SCRs, ammonia is injected into the flue gas and reacts with NOx to form nitrogen and water in the presence of catalyst. SCR catalysts are made from ceramic materials and active catalytic components of base metals, zeolites, or precious metals. The catalyst may be configured into plates but many new systems are configured into honeycomb structure to ensure uniform dispersion and to reduce ammonia slip emissions to less than five ppmv. The reductant, ammonia, is available as anhydrous ammonia, aqueous ammonia, or urea. However, because anhydrous ammonia is an acutely hazardous material which poses safety risks, South Coast AQMD does not permit new installations of anhydrous ammonia storage tanks for air pollution control purposes. Urea pellets is a safer alternative to anhydrous ammonia but requires conversion to aqueous ammonia in order to be used in SCRs. Most new SCRs installations utilize aqueous ammonia in a 19 percent solution.

To perform optimally, the temperature of the exhaust gas as it is routed through the SCR needs to be between 400 degrees Fahrenheit and 800 degrees Fahrenheit in order for the SCR catalyst to be fully activated. During start-up and shutdown of the turbine, the temperature of the exhaust will be below optimal range greatly reducing the effectiveness of the SCR's ability to reduce NOx emissions. For this reason, NOx concentration limits are generally not applicable during start-up or shutdown.

The catalyst is susceptible to "poisoning" if the flue gas contains contaminants including sulfur compounds, particulates, reagent salts, or siloxanes. Because these contaminants are readily found in digester gas, and other biogas, gas treatment of the fuel to remove these contaminants may be necessary to prevent the poisoning catalysts requiring the unit to be shut down for cleaning or replacement.

Replacement with New Turbines

Newer gas turbines are capable of achieving low NOx emission levels between four and 25 ppm when firing natural gas without SCR. Achievable NOx emission levels while firing digester gas vary and depend on the chemical composition of the digester gas. Dry low NOx systems are incompatible with digester gas due to the low Wobbe index number for digester gas, but there is one commercially available 4.6 MW recuperative turbine that incorporates a dry low NOx system compatible with biogas. There is one turbine on the market whose manufacturer guarantees NOx emission levels at 25 ppm, corrected at 15 percent oxygen on a dry basis, for digester gas. Two other turbine manufacturers produce turbines with estimated NOx emission levels of 15 ppm and 25 ppm when firing digester gas with the latter for the larger sized turbines in the 10 MW range. Another turbine manufacturer has claimed to be able to guarantee NOx emissions levels of 15 ppm and 25 ppm, corrected at 15 percent oxygen on a dry basis, depending on the model, for turbines fueled by digester gas, without requiring SCR technology.

Internal Combustion Engines using Gaseous Fuel

Internal combustion engines create power by mixing fuel in a cylinder controlled by valves in a timed cycle. The cylinder contains a piston which compresses the fuel igniting it by either a spark (spark ignition) or until the fuel ignites from pressure (compression ignition). The expansive force created by the ignited fuel is transferred by the piston through a connecting rod to a crankshaft which transfers the resulting power to useable work. The power created can generate electricity or, by an external shaft, propulsion. The extreme heat created by the combustion of the fuel exits the engine through the exhaust system at a temperature sufficient to create undesirable pollutants such as NOx and greenhouse gases such as CO2, methane and nitrous oxide (N2O). The emissions are often controlled by complex catalyst systems for compression ignition engines, or a single simple catalyst for spark ignited engines.

PR 1179.1 applies to engines at POTWs, but these engines will continue to be subject to the same permitted emission limits as contained in Rule 1110.2.

PROJECT DESCRIPTION

This section provides a general summary of the key elements contained in PR 1179.1. Additional information about ~~A preliminary draft of~~ PR 1179.1 can be found in Appendix A.

PR 1179.1 establishes emission limits for boilers (which include steam generators and process heaters) rated greater than 400,000 Btu per hour, turbines rated at less than 0.3 MW, and engines operated at POTWs, that either use digester gas or a blend of digester gas and natural gas as fuel, and turbines rated at 0.3 MW and larger. PR 1179.1 excludes boilers (as well as steam generators and process heaters) that use natural gas as the exclusive fuel type because these equipment categories are subject to the requirements in Rule 1146 series. PR 1179.1 also excludes engines that use exclusively natural gas or diesel fuel because these equipment categories are subject to the requirements in Rule 1110.2. Lastly, PR 1179.1 establishes BARCT for all turbines rated at greater than or equal to 0.3 MW operated at POTWs, irrespective of whether digester gas, natural gas, or digester gas that is blended with natural gas is used as a fuel, since Rule 1134 (which regulates turbines) specifically excludes turbines located at POTW facilities in the rule applicability. Table 1-1 summarizes the emission limits for the affected equipment.

The applicable emission limits in PR 1179.1 for engines, boilers and turbines operated at POTWs will go into effect the date the rule is adopted.

In addition, the proposed project also includes source testing, as well as monitoring, recordkeeping, and reporting requirements. Further, PR 1179.1 provides the following limited exemptions from the emission limits in Table 1-1 for the following equipment categories: 1) low-use boilers subject applicable requirements in Rule 1146; 2) special use turbines such as for the purpose of flood control and providing emergency backup power; 3) natural gas boilers and engines subject to the requirements in either the Rule 1146 series or Rule 1110.2, as applicable; 4) low-use engines that operate less than 200 hours or less per year; 5) turbines rated less than 0.3 MW and in operation prior to May 3, 2013; and 6) existing small boilers rated at less than or equal to two million Btu per hour without NOx concentration limits specified in the permits.

Subsequent to the circulation of the Draft EA for public comment and review, the following modifications were made to PR 1179.1: 1) revising the rule title; and 2) incorporating other minor edits and clarifications. These changes are considered to be administrative in nature with no potential to create new or modify the environmental impacts previously analyzed. As such, no revisions to analysis and the conclusions reached were necessary. Thus, staff's review of the modifications to PR 1179.1 since the Draft EA was released indicate that none of the resulting revisions to the Draft EA: 1) constitute significant new information; 2) constitute a substantial increase in the severity of an environmental impact; or, 3) provide new information of substantial importance relative to the Draft EA. In addition, revisions to the proposed project 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 EA pursuant to CEQA Guidelines Sections 15073.5 and 15088.5.

Implementation of the proposed project is expected to reduce NOx emissions by 0.05 ton per day and will provide an overall environmental benefit to air quality.

Table 1-1
PR 1179.1 Concentration Limits

BOILERS, STEAM GENERATORS, AND PROCESS HEATERS FIRED ON DIGESTER GAS OR DIGESTER GAS BLEND				
EQUIPMENT CATEGORY	NOx (ppm)[1]	CO (ppm)[1]	VOC (ppm)	COMPLIANCE DATE
Rated heat input capacity > 2 MMBtu/hr	15	400	N/A	On or before [*Date of Adoption*]
Rated heat input capacity ≤ 2 MMBtu/hr	30			On or before [*Date of Adoption*]
TURBINES FIRED ON DIGESTER GAS, DIGESTER GAS BLEND, OR NATURAL GAS				
EQUIPMENT CATEGORY	NOx (ppm)[2]	CO (ppm)[2]	VOC (ppm)	COMPLIANCE DATE
Rating ≥ 0.3 MW firing 40% natural gas or less	18.8	130	N/A	On or before [*Date of Adoption*]
Simple cycle with rating ≥ 0.3 MW firing more than 40% natural gas	5			On or before [*Date of Adoption*]
Combined cycle with rating ≥ 0.3 MW firing more than 40% natural gas	2			On or before [*Date of Adoption*]
Rating < 0.3 MW firing digester gas or digester gas with natural gas	9			On or before [*Date of Adoption*]
ENGINES FIRED ON DIGESTER GAS OR DIGESTER GAS BLEND				
EQUIPMENT CATEGORY	NOx (ppm)[2]	CO (ppm)[2]	VOC (ppm)[3]	COMPLIANCE DATE
Engines > 50 bhp	11	250	30	On or before [*Date of Adoption*]

1 All parts per million (ppm) emission limits are referenced at 3% volume stack gas oxygen on a dry basis.
2 All parts per million (ppm) emission limits are referenced at 15% volume stack gas oxygen on a dry basis.
3 Parts per million (ppm) by volume, measured as carbon, corrected to 15% oxygen on a dry basis.

SUMMARY OF AFFECTED FACILITIES AND EQUIPMENT

Implementation of PR 1179.1 will apply to 30 POTW facilities operating 82 pieces of equipment that include boilers, turbines, and engines. A list of these facilities is provided in Appendix B of this EA. Each facility subject to PR 1179.1 is classified by the North American Industry Classification System (NAICS) code, as 221320 – Sewage Treatment Facilities.

Of the 30 facilities in South Coast AQMD's jurisdiction that are subject to PR 1179.1, no physical modifications to any combustion equipment are anticipated to be necessary in order to comply with the proposed emission limits in PR 1179.1. Most turbines subject to PR 1179.1 currently operate pursuant to South Coast AQMD permits which contain the emission limits proposed in PR 1179.1. Only one POTW facility that operates three turbines that are each rated greater than 0.3 MW would be expected to make some operational changes in order to achieve the proposed NOx emission limit proposed in PR 1179.1. That facility has indicated that they can achieve this NOx emission limit by increasing the amount of water that is currently injected into the combustion chamber as a NOx emission reduction measure and this operational change can be accomplished without the need to either install additional NOx emission control equipment such as SCR or replace their turbines. The facility estimated that an additional 8,000 gallons per day per turbine for a total of 24,000 gallons per day would be needed to supplement their existing water injection activities. Because this is an operational change that does not require any physical modifications to existing piping to supply the additional water, no construction activities are expected to occur at this facility.

The remaining POTW boilers, turbines, and engines are not expected to undergo any physical modifications because they are currently achieving the applicable emission limits that are being migrated from Rules 1146, 1146.1 and 1146.2, Rule 1110.2 or existing permit limits for incorporation into PR 1179.1. Table 1-2 identifies the POTW with the potentially affected turbines.

Table 1-2
Potentially Affected Turbines

Facility ID	Facility Name	Type of Equipment	Number of Affected Equipment
800236	LA County Joint Water Pollution Control Plant	Digester Gas-Fired Turbine	3

CHAPTER 2

ENVIRONMENTAL CHECKLIST

INTRODUCTION

The environmental checklist provides a standard evaluation tool to identify a project's potential adverse environmental impacts. This checklist identifies and evaluates potential adverse environmental impacts that may be created by the proposed project.

GENERAL INFORMATION

Project Title:	Proposed Rule 1179.1 – ~~NOx~~ Emissions Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities
Lead Agency Name:	South Coast Air Quality Management District
Lead Agency Address:	21865 Copley Drive Diamond Bar, CA 91765
CEQA Contact Person:	Ms. Kendra Reif, (909) 396-2492
PR 1179.1 Contact Person:	Ms. Melissa Gamoning, (909) 396-3115
Project Sponsor's Name:	South Coast Air Quality Management District
Project Sponsor's Address:	21865 Copley Drive Diamond Bar, CA 91765
General Plan Designation:	Not applicable
Zoning:	Not applicable
Description of Project:	PR 1179.1 proposes to establish BARCT requirements for combustion equipment operated at POTW facilities to reduce emissions of: 1) NOx and CO from boilers, steam generators and process heaters rated greater than 400,000 Btu per hour fueled by digester gas or a digester gas blend; 2) NOx and CO from turbines rated less than 0.3 MW fueled by digester gas or a digester gas blend; 3) NOx and CO from turbines rated at greater than or equal to 0.3 MW fueled by natural gas, digester gas, or a digester gas blend; and 4) NOx, CO, and VOC from engines rated at greater than 50 bhp fueled by digester gas or a digester gas blend. In addition, PR 1179.1 establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. PR 1179.1 is estimated to reduce up to 0.05 ton per day of NOx emissions. The Final ~~Draft~~ EA did not result in the identification of any environmental topic areas that would be significantly adversely affected by PR 1179.1. Two facilities affected by PR 1179.1 were identified on lists compiled by the California Department of Toxic Substances Control per Government Code Section 65962.5.
Surrounding Land Uses and Setting:	Various
Other Public Agencies Whose Approval is Required:	Not applicable

ENVIRONMENTAL FACTORS POTENTIALLY AFFECTED

The following environmental impact areas have been assessed to determine their potential to be affected by the proposed project. As indicated by the checklist on the following pages, environmental topics marked with an "✓"involve at least one impact that is a "Potentially Significant Impact". An explanation relative to the determination of impacts can be found following the checklist for each area.

☐	Aesthetics	☐	Geology and Soils	☐	Population and Housing
☐	Agriculture and Forestry Resources	☐	Hazards and Hazardous Materials	☐	Public Services
☐	Air Quality and Greenhouse Gas Emissions	☐	Hydrology and Water Quality	☐	Recreation
☐	Biological Resources	☐	Land Use and Planning	☐	Solid and Hazardous Waste
☐	Cultural and Tribal Cultural Resources	☐	Mineral Resources	☐	Transportation
☐	Energy	☐	Noise	☐	Wildfire
☐	Mandatory Findings of Significance				

DETERMINATION

On the basis of this initial evaluation:

- ☑ I find the proposed project, in accordance with those findings made pursuant to CEQA Guidelines Section 15252, COULD NOT have a significant effect on the environment, and that an ENVIRONMENTAL ASSESSMENT with no significant impacts has been prepared.
- ☐ I find that although the proposed project could have a significant effect on the environment, there will NOT be significant effects in this case because revisions in the project have been made by or agreed to by the project proponent. An ENVIRONMENTAL ASSESSMENT with no significant impacts will be prepared.
- ☐ I find that the proposed project MAY have a significant effect(s) on the environment, and an ENVIRONMENTAL ASSESSMENT will be prepared.
- ☐ I find that the proposed project MAY have a "potentially significant impact" on the environment, but at least one effect: 1) has been adequately analyzed in an earlier document pursuant to applicable legal standards; and, 2) has been addressed by mitigation measures based on the earlier analysis as described on attached sheets. An ENVIRONMENTAL ASSESSMENT is required, but it must analyze only the effects that remain to be addressed.
- ☐ I find that although the proposed project could have a significant effect on the environment, because all potentially significant effects: 1) have been analyzed adequately in an earlier ENVIRONMENTAL ASSESSMENT pursuant to applicable standards; and, 2) have been avoided or mitigated pursuant to that earlier ENVIRONMENTAL ASSESSMENT, including revisions or mitigation measures that are imposed upon the proposed project, nothing further is required.

Date: August 7, 2020 **Signature:** Barbara Radlein

Barbara Radlein
Program Supervisor, CEQA
Planning, Rule Development and Area Sources

ENVIRONMENTAL CHECKLIST AND DISCUSSION

As explained in Chapter 1, the main focus of PR 1179.1 is to establish BARCT requirements for combustion equipment operated at POTWs and to consolidate and migrate all POTW-applicable requirements from Rules 1146, 1146.1 and 1146.2, Rule 1134, and Rule 1110.2 in order to consolidate all of these requirements into one rule. Specifically, the BARCT requirements are designed to reduce emissions of: 1) NOx and CO from boilers, steam generators and process heaters rated greater than 400,000 Btu per hour and fueled by digester gas or a digester gas blend; 2) NOx and CO from turbines rated less than 0.3 MW fueled by digester gas or a digester gas blend; 3) NOx and CO from turbines rated at greater than or equal to 0.3 MW fueled by natural gas, digester gas, or a digester gas blend; and 4) NOx, CO and VOC from engines greater than 50 bhp fueled by digester gas or a digester gas blend. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports.

Of the 30 facilities in South Coast AQMD's jurisdiction that are subject to PR 1179.1, no physical modifications to any combustion equipment are anticipated to be necessary in order to comply with the proposed emission limits in PR 1179.1 because they currently operate pursuant to South Coast AQMD permits which contain the applicable emission limits. Only one POTW facility that operates three turbines that are each rated greater than 0.3 MW would be expected to make some relatively minor operational changes in order to achieve the 18.8 ppm NOx emission limit to comply with PR 1179.1. The facility has indicated that they can achieve this NOx emission limit by increasing the amount of water that is currently injected into the combustion chamber as a NOx emission reduction measure and this operational change can be accomplished without the need to either install additional NOx emission control equipment such as SCR or replace their turbines. The facility estimated that an additional 8,000 gallons per day per turbine for a total of 24,000 gallons per day would be needed to supplement their existing water injection activities. Because this is an operational change that does not require any physical modifications to existing piping to supply the additional water, no construction activities are expected to occur at this facility. The following components of PR 1179.1 are administrative or procedural in nature and as such, would not be expected to cause any physical modifications at affected facilities: conducting monitoring, keeping records, and preparing reports. As such, these components of PR 1179.1 would not be expected to create any secondary adverse environmental impacts.

Also, PR 1179.1 contains requirements for POTW facilities to conduct source tests. Wastewater treatment plants are already required by other existing rules to conduct periodic source tests for most combustion equipment subject to this rule. However, POTW operators of turbines rated at less than 0.3 MW are not currently subject to any existing South Coast AQMD rule but would be required to conduct source tests under PR 1179.1.

PR 1179.1 is estimated to reduce up to 0.05 ton per day of NOx emissions, as a result of one facility increasing the quantity of water injected into the three turbines in order to achieve NOx emissions at a concentration of less than 18.8 ppm. For these reasons, the analysis in this EA focuses on the potential secondary adverse environmental impacts associated with the increased amount of water injection. The effects of the potential increased water usage have been evaluated relative to the environmental topics identified in the following environmental checklist (e.g., aesthetics, agriculture and forestry resources, biological resources, etc.).

<u>Subsequent to the circulation of the Draft EA for public comment and review, the following modifications were made to PR 1179.1: 1) revising the rule title; and 2) incorporating other minor edits and clarifications. These changes are considered to be administrative in nature with no</u>

potential to create new or modify the environmental impacts previously analyzed. As such, no revisions to analysis and the conclusions reached were necessary. Thus, staff's review of the modifications to PR 1179.1 since the Draft EA was released indicate that none of the resulting revisions to the Draft EA: 1) constitute significant new information; 2) constitute a substantial increase in the severity of an environmental impact; or, 3) provide new information of substantial importance relative to the Draft EA. In addition, revisions to the proposed project 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 EA pursuant to CEQA Guidelines Sections 15073.5 and 15088.5.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
I. AESTHETICS. Would the project:				
a) Have a substantial adverse effect on a scenic vista?	☐	☐	☐	☑
b) Substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?	☐	☐	☐	☑
c) In non-urbanized areas, substantially degrade the existing visual character or quality of public views of the site and its surroundings? (Public views are those that are experienced from publicly accessible vantage point(s).) If the project is in an urbanized area, would the project conflict with applicable zoning or other regulations governing scenic quality?	☐	☐	☐	☑
d) Create a new source of substantial light or glare which would adversely affect day or nighttime views in the area?	☐	☐	☐	☑

Significance Criteria

The proposed project impacts on aesthetics will be considered significant if:

- The project will block views from a scenic highway or corridor.
- The project will adversely affect the visual continuity of the surrounding area.
- The impacts on light and glare will be considered significant if the project adds lighting which would add glare to residential areas or sensitive receptors.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

I. a), b), c) & d) No Impact. Of the 30 facilities in South Coast AQMD's jurisdiction that are subject to PR 1179.1, none of the facilities will need to make any physical modifications to comply with the emission reduction requirements in PR 1179.1 because their combustion equipment currently operate pursuant to South Coast AQMD permits which contain applicable emission limits. Only one POTW facility that operates three turbines rated greater than 0.3 MW would be expected to make some relatively minor operational changes in order to achieve the 18.8 ppm NOx emission limit to comply with PR 1179.1. To specifically reduce NOx emissions, one facility would need to increase their total water usage by 24,000 gallons per day as part of their existing water injection process for their three turbines. The additional water usage would not require physical modifications to existing piping or water pumping systems. Thus, no additional construction at the facility would be expected.

Because the increased water injection activities will occur within the boundaries of the affected facility and none of the affected facilities will be expected to make physical modifications in order to comply with PR 1179.1, views of any scenic vistas or state scenic highways will not be obstructed. For the same reasons, implementation of PR 1179.1 would have no substantial adverse effect on scenic vistas or other scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway.

Similarly, PR 1179.1 would not require the alteration of buildings or other equipment. The potential increased quantity of water injection that may occur at one POTW would not require any approvals from the local city or county planning departments. Therefore, PR 1179.1 would not be expected to conflict with applicable zoning or other regulations governing scenic quality.

Since PR 1179.1 does not include any components that would involve construction activities or additional physical modifications to the facility requiring supplemental lighting, no additional temporary construction lighting or permanent lighting at any of the facilities subject to PR 1179.1 would be expected. For these reasons, the proposed project would not create a new source of substantial light or glare.

Conclusion

Based upon these considerations, significant adverse aesthetics impacts are not expected from implementing PR 1179.1. Since no significant aesthetics impacts were identified, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
II.	**AGRICULTURE AND FORESTRY RESOURCES.** Would the project:				
a)	Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the Farmland mapping and Monitoring Program of the California Resources Agency, to non- agricultural use?	☐	☐	☐	☑
b)	Conflict with existing zoning for agricultural use, or a Williamson Act contract?	☐	☐	☐	☑
c)	Conflict with existing zoning for, or cause rezoning of, forest land (as defined in Public Resources Code §12220(g)), timberland (as defined by Public Resources Code §4526), or timberland zoned Timberland Production (as defined by Government Code §51104(g))?	☐	☐	☐	☑
d)	Result in the loss of forest land or conversion of forest land to non-forest use?	☐	☐	☐	☑
e)	Involve other changes in the existing environment which, due to their location or nature, could result in the conversion of Farmland, to non-agricultural use or conversion of forest land to non-forest use?	☐	☐	☐	☑

Significance Criteria

Project-related impacts on agriculture and forest resources will be considered significant if any of the following conditions are met:

- The proposed project conflicts with existing zoning or agricultural use or Williamson Act contracts.
- The proposed project will convert prime farmland, unique farmland or farmland of statewide importance as shown on the maps prepared pursuant to the farmland mapping and monitoring program of the California Resources Agency, to non-agricultural use.
- The proposed project conflicts with existing zoning for, or causes rezoning of, forest land (as defined in Public Resources Code §12220(g)), timberland (as defined in Public Resources

Code §4526), or timberland zoned Timberland Production (as defined by Government Code §51104(g)).

- The proposed project would involve changes in the existing environment, which due to their location or nature, could result in conversion of Farmland to non-agricultural use or conversion of forest land to non-forest use.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

II. a), b), c), d), & e) No Impact. No locations of the 30 facilities subject to PR 1179.1 or their immediately surrounding areas are on or near areas zoned for agricultural use, Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the Farmland Mapping and Monitoring Program of the California Resources Agency. Further, the proposed project would not require any construction or alterations to any of the facilities subject to PR 1179.1 and it would not require the conversion of farmland to non-agricultural use or conflict with zoning for agriculture use or a Williamson Act contract.

The locations of the facilities subject to PR 1179.1 are sited in industrial use zones in urbanized areas that are not located near forest land. Therefore, the proposed project is not expected to conflict with existing zoning for, or cause rezoning of, forest land (as defined in Public Resources Code Section 12220(g)), timberland (as defined by Public Resources Code Section 4526), or timberland zoned Timberland Production (as defined by Government Code Section 51104(g)) or result in the loss of forest land or conversion of forest land to non-forest use.

Conclusion

Based upon these considerations, significant adverse agriculture and forestry resources impacts are not expected from implementing PR 1179.1. Since no significant agriculture and forestry resources impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
III. AIR QUALITY AND GREENHOUSE GAS EMISSIONS. Would the project:				
a) Conflict with or obstruct implementation of the applicable air quality plan?	☐	☐	☐	☑
b) Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is non-attainment under an applicable federal or state ambient air quality standard?	☐	☐	☑	☐
c) Expose sensitive receptors to substantial pollutant concentrations?	☐	☐	☑	☐
d) Create objectionable odors affecting a substantial number of people?	☐	☐	☑	☐
e) Diminish an existing air quality rule or future compliance requirement resulting in a significant increase in air pollutant(s)?	☐	☐	☑	☐
f) Generate greenhouse gas emissions, either directly or indirectly, that may have a significant impact on the environment?	☐	☐	☑	☐
g) Conflict with an applicable plan, policy or regulation adopted for the purpose of reducing the emissions of greenhouse gases?	☐	☐	☑	☐

Significance Criteria

To determine whether or not air quality and greenhouse gas impacts from implementing PR 1179.1 are significant, impacts will be evaluated and compared to the criteria in Table 2-1 PR 1179.1 will be considered to have significant adverse impacts if any one of the thresholds in Table 2-1 are equaled or exceeded.

Table 2-1
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

Revision: April 2019

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. Two facilities that contain five turbines less than 0.3 MW each are expected to require new periodic source testing pursuant to subdivision (e) of the proposed rule. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

a) No Impact. The South Coast AQMD is required by law to prepare a comprehensive district-wide Air Quality Management Plan (AQMP) which includes strategies (e.g., control measures) to reduce emission levels to achieve and maintain state and federal ambient air quality standards, and to ensure that new sources of emissions are planned and operated to be consistent with the SCAQMD's air quality goals. The AQMP's air pollution reduction strategies include control measures which target stationary, area, mobile and indirect sources. These control measures are based on feasible methods of attaining ambient air quality standards. Pursuant to the provisions of both the state and federal Clean Air Acts, the South Coast AQMD is also required to attain the state and federal ambient air quality standards for all criteria pollutants.

The most recent regional blueprint for how the South Coast will achieve air quality standards and healthful air is outlined in the 2016 AQMP[8] which contains multiple goals of promoting reductions of criteria air pollutants, greenhouse gases, and toxics. In particular, the 2016 AQMP includes control measure CMB-05 which committed to additional NOx emission reductions of five tons per day to occur by 2025. PR 1179.1 proposes to establish BARCT limits for equipment operated at POTWs to reduce NOx and CO from certain boilers, steam generators and process heaters, turbines and engines. In addition, PR 1179.1 will regulate emissions of VOC from certain engines.

For these reasons, PR 1179.1 is not expected to obstruct or conflict with the implementation of the 2016 AQMP because the emission reductions from implementing PR 1179.1 are in accordance with the overall emission reduction goals in the 2016 AQMP. Thus, implementing PR 1179.1 to reduce emissions from equipment located at POTWs would not conflict with or obstruct implementation of the applicable air quality plans.

[8] South Coast AQMD, Final 2016 Air Quality Management Plan, March, 2017. http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2016-air-quality-management-plan/final-2016-aqmp/final2016aqmp.pdf

b) and e) Less Than Significant Impact. PR 1179.1 is designed to establish emission limits that are representative of BARCT for NOx, CO, and VOC emissions from engines and BARCT for NOx and CO emissions from boilers/steam generators, process heaters, and turbines located at POTWs that were not addressed in other source-specific rules. Of the 30 facilities that will be subject to PR 1179.1 after adoption, none of the facilities will need to make any physical modifications to comply with the emission reduction requirements in PR 1179.1 because their combustion equipment currently operate pursuant to South Coast AQMD permits which contain applicable emission limits. Only one POTW facility that operates three large turbines (each are rated greater than 0.3 MW) is expected to make an operational change related to increasing the amount of water injected into the combustion chambers in order to achieve the 18.8 ppm NOx emission limit to comply with PR 1179.1. The facility has indicated that they can achieve this NOx emission limit by increasing the amount of water that is currently injected into the combustion chamber as a NOx emission reduction measure without having to either install additional NOx emission control equipment such as SCR or replace or retrofit their turbines. The facility estimated that an additional 8,000 gallons per day per turbine for a total of 24,000 gallons per day would be needed to supplement their existing water injection activities. Increasing the amount of demineralized water needed for water injection purposes is not change that would require physical modifications to the existing plumbing. Thus, no construction activities are expected to occur.

Since the turbines currently employ water injection for NOx emission control purposes, increasing the amount of water injected into the turbines is a matter of adjusting the flow rate and is expected to occur as part of normal day-to-day operations of the turbines. The facility has provided the following additional information regarding the anticipated increase in water injected into the turbines:

- The facility has its own supply of water and the increase in water injection can be employed immediately by adjusting the water input flow rate;
- Negligible changes to CO emissions from the turbines are expected based on monitoring data; and
- Injecting additional water may require increased maintenance due to erosion and wear on turbine equipment but the maintenance can be conducted by existing employees so no additional workers or vendors will be needed.

Two facilities, each with five turbines (less than 0.3 MW), will be required to conduct source tests on each turbine. Owners/operators of affected facilities would be expected to hire a contractor to conduct the source tests. Since the turbines are relatively small, one crew (comprised of two workers) is capable of source testing all turbines at one facility on a single day.

For a worst-case scenario, this analysis assumes that both facilities will be conducting source tests on the same day. Each source testing crew is assumed to drive one light-duty gasoline-fueled truck with a fuel economy rating averaging 21 miles per gallon (mpg) and one medium-duty diesel-fueled maintenance truck with a fuel economy rating averaging 10 mpg. Each vehicle is assumed to drive approximately 40 miles round trip to conduct the source tests at each facility.

Operational Impacts

Total operational emissions were estimated using emission factors for on-road vehicles from CARB's EMFAC2017[1] for the following mobile sources: medium-duty diesel fueled trucks used to provide source testing support; light duty gasoline-fueled passenger vehicles used for transporting workers to facilities in order to conduct source tests.

Table 2-2 summarizes the peak daily emissions associated with operation. A peak day of operation is assumed to consist of source testing at two facilities on the same day. Additional details of the assumptions and calculations can be found in Appendix B.

Table 2-2
Peak Daily Operational Emissions by Pollutant (lb/day)

Activity	VOC	NOx	CO	SOx	PM10	PM2.5
One Light Duty Auto Worker Trip to Conduct Source Testing	0.02	0.19	0.10	0.00	0.02	0.01
One Medium Duty Truck Trip to Conduct Source Testing	0.02	0.01	0.15	0.00	0.00	0.00
One Source Test	**0.03**	**0.20**	**0.24**	**0.00**	**0.02**	**0.01**
Two Source Tests	**0.07**	**0.40**	**0.49**	**0.00**	**0.04**	**0.02**
Significance Threshold	**55**	**55**	**550**	**150**	**150**	**55**
Significant?	**No**	**No**	**No**	**No**	**No**	**No**

Assumptions: Though unlikely, a peak day is assumed to include source testing at two facilities. See Appendix B for additional assumptions and calculations.

The air quality analysis indicates that the peak daily emissions do not exceed the South Coast AQMD's air quality significance thresholds for any pollutant during operation; Therefore, the physical activities that are expected to occur as a result of implementing PR 1179.1 are not expected to cause any air quality impacts either during construction or operation.

Construction and Operational Impacts

In conclusion, the air quality analysis indicates that no increase in peak daily emissions during construction is expected to occur and a less than significant increase in peak daily emissions during operation is expected to occur; thus, the proposed project is not expected to result in significant adverse air quality impacts.

Cumulatively Considerable Impacts

Based on the foregoing analysis, there will be no criteria pollutant project-specific air quality impacts from implementing PR 1179.1 during construction or operation. Therefore, cumulative air quality impacts are also not expected to occur since South Coast AQMD's cumulative significance thresholds are the same as project-specific significance thresholds. Potential adverse impacts from implementing PR 1179.1 would not be "cumulatively considerable" as defined by CEQA Guidelines Section 15064(h)(1) for air quality impacts. Per CEQA Guidelines Section 15064(h)(4), the mere existence of significant cumulative impacts caused by other projects alone shall not constitute substantial evidence that the proposed project's incremental effects are cumulatively considerable.

The South Coast AQMD's guidance on addressing cumulative impacts for air quality is as follows: "As Lead Agency, the South Coast AQMD uses the same significance thresholds for project specific and cumulative impacts for all environmental topics analyzed in an Environmental Assessment or EIR." "Projects that exceed the project-specific significance thresholds are considered by the South Coast AQMD to be cumulatively considerable. This is the reason project-specific and cumulative significance thresholds are the same. Conversely, projects that do not exceed the project-specific thresholds are generally not considered to be cumulatively significant."[9]

This approach was upheld by the Court in Citizens for Responsible Equitable Environmental Development v. City of Chula Vista (2011) 197 Cal. App. 4th 327, 334. The Court determined that where it can be found that a project did not exceed the South Coast AQMD's established air quality significance thresholds, the City of Chula Vista properly concluded that the project would not cause a significant environmental effect, nor result in a cumulatively considerable increase in these pollutants. The court found this determination to be consistent with CEQA Guidelines Section 15064.7, stating, "The lead agency may rely on a threshold of significance standard to determine whether a project will cause a significant environmental effect." The court found that, "Although the project will contribute additional air pollutants to an existing non-attainment area, these increases are below the significance criteria…" "Thus, we conclude that no fair argument exists that the Project will cause a significant unavoidable cumulative contribution to an air quality impact." As in Chula Vista, here the South Coast AQMD has demonstrated, when using accurate and appropriate data and assumptions, that the project will not exceed the established South Coast AQMD significance thresholds. See also, Rialto Citizens for Responsible Growth v. City of Rialto (2012) 208 Cal. App. 4th 899. Here again the court upheld the South Coast AQMD's approach to utilizing the established air quality significance thresholds to determine whether the impacts of a project would be cumulatively considerable. Thus, it may be concluded that the proposed project will not contribute to a significant unavoidable cumulative air quality impact.

c) Less than Significant Impact. Since no physical modifications are expected to occur as a result of compliance with PR 1179.1 that would cause construction or operation air quality emission impacts, the effects of implementing PR 1179.1 would not be expected to adversely affect sensitive receptors located near any of the facilities subject to PR 1179.1. Further, the proposed project will require equipment located at POTW facilities to achieve BARCT emission levels which will result in NOx emission reductions, an air quality benefit. Therefore, PR 1179.1 is not expected to expose sensitive receptors to substantial pollutant concentrations.

d) Less Than Significant Impact. Odor problems depend on individual circumstances. For example, individuals can differ quite markedly from the populated average in their sensitivity to odor due to any variety of innate, chronic or acute physiological conditions. This includes olfactory adaptation or smell fatigue (i.e., continuing exposure to an odor usually results in a gradual diminution or even disappearance of the small sensation).

Implementation of PR 1179.1 will only require a physical change at one POTW to inject increased amounts of demineralized water into the three existing turbines and demineralized water does not have a perceptible odor. Further, no additional worker or vendor trips are expected to be needed during maintenance or source testing activities that would require the additional use of diesel-fueled vehicles capable of generating diesel exhaust odor greater than what is already typically present at the affected facilities. Thus, PR 1179.1 is not expected to create significant adverse

[9] South Coast AQMD Cumulative Impacts Working Group White Paper on Potential Control Strategies to Address Cumulative Impacts From Air Pollution, August 2003, Appendix D, Cumulative Impact Analysis Requirements Pursuant to CEQA, at D-3. http://www.aqmd.gov/docs/default-source/Agendas/Environmental-Justice/cumulative-impacts-working-group/cumulative-impacts-white-paper-appendix.pdf

objectionable odors during construction or operation. Since no significant air quality impacts were identified for odors, no mitigation measures for odors are necessary or required.

III. f) and g) Less Than Significant Impact. Significant changes in global climate patterns have recently been associated contributing to an average increase in the temperature of the atmosphere near the Earth's surface, attributed to accumulation of greenhouse gas (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) (Health and Safety Code Section 38505(g)). The most common GHG that results from human activity is CO2, followed by CH4 and N2O.

As previously explained in Section III. b) and e), implementation of PR 1179.1 is not expected to cause an adverse increase of criteria air pollutants, including CO2, which is a GHG. Table 2-3 summarizes the GHG analysis which shows that PR 1179.1 may result in the generation of 0.10 MT per year of CO2eq, which is less than the South Coast AQMD's air quality significance threshold for GHGs. The detailed calculations of project GHG emissions can be found in Appendix B.

Summary of GHG Emissions from Affected Facilities

Phase	**Activity**	**CO2 Emissions (MT/yr)**
Operation	Source Test Trips	0.10
	Subtotal	0.10
	Total Emissions	**0.10**
	Significance Threshold	10,000
	Significant?	**No**

As shown in Table 2-3, the South Coast AQMD air quality significance threshold for GHGs would not be exceeded. For this reason, implementing the proposed project would not be expected to generate significant adverse cumulative GHG air quality impacts. Further, as noted in Section III. a), implementation of PR 1179.1 would not be expected to conflict with an applicable plan, policy or regulation adopted for the purpose of reducing criteria pollutants and the same is true for GHG emissions since GHG emissions would not be impacted in any way by PR 1179.1. Therefore, GHG impacts are not considered significant. Since no significant air quality impacts were identified for GHGs, no mitigation measures are necessary or required

Conclusion

Based upon these considerations, significant air quality and GHG emissions impacts are not expected from implementing PR 1179.1. Since no significant air quality and GHG emissions impacts were identified, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
IV.	**BIOLOGICAL RESOURCES.** Would the project:				
a)	Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special status species in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service?	☐	☐	☐	☑
b)	Have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service?	☐	☐	☐	☑
c)	Have a substantial adverse effect on federally protected wetlands as defined by Section 404 of the Clean Water Act (including, but not limited to, marsh, vernal pool, coastal, etc.) through direct removal, filling, hydrological interruption, or other means?	☐	☐	☐	☑
d)	Interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites?	☐	☐	☐	☑
e)	Conflict with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance?	☐	☐	☐	☑
f)	Conflict with the provisions of an adopted Habitat Conservation plan, Natural Community Conservation Plan, or other approved local, regional, or state habitat conservation plan?	☐	☐	☐	☑

Significance Criteria

Impacts on biological resources will be considered significant if any of the following criteria apply:

- The project results in a loss of plant communities or animal habitat considered to be rare, threatened or endangered by federal, state or local agencies.
- The project interferes substantially with the movement of any resident or migratory wildlife species.
- The project adversely affects aquatic communities through construction or operation of the project.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18.8 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

IV. a), b), c), & d) No Impact. All 30 POTWs are existing facilities located industrial areas and none will need to make any physical modifications to comply with the emission reduction requirements in PR 1179.1 because they currently operate pursuant to South Coast AQMD permits which contain applicable emission limits. Only one POTW facility that operates three turbines which are each rated greater than 0.3 MW would be expected to make some relatively minor operational changes in order to achieve the 18.8 ppm NOx emission limit to comply with PR 1179.1. To specifically reduce NOx emissions, one facility would need to increase their total water usage by 24,000 gallons per day as part of their existing water injection process for their three turbines. The additional water usage would not require physical modifications to existing piping or water pumping systems. Thus, no additional construction at the facility would be expected. Further, because the increased water injection activities will occur within the boundaries of the affected facility and no other facilities will be expected to make physical modifications in order to comply with PR 1179.1, the proposed project is not expected to adversely affect in any way habitats that support riparian habitat, federally protected wetlands, or migratory corridors. Similarly, special status plants, animals, or natural communities identified in local or regional plans, policies, or regulations, or by the California Department of Fish and Wildlife or U.S. Fish and Wildlife Service are not expected to disturb if PR 1179.1 is implemented. Therefore, PR 1179.1 would have no direct or indirect impacts that could adversely affect plant or animal species or the habitats on which they rely. PR 1179.1 does not require the acquisition of additional land or further conversions of riparian habitats or sensitive natural communities where endangered or sensitive species may be found. In addition, the implementation of PR 1179.1 does not require any construction therefore, it would not affect any wetlands or impact the path of migratory bird species.

IV. e) & f) No Impact. The proposed project is not expected to conflict with local policies or ordinances protecting biological resources or local, regional, or state conservation plans, because land use and other planning considerations are determined by local governments and no land use or planning requirements would be altered by implementation of PR 1179.1. Additionally, PR 1179.1 would not conflict with any adopted Habitat Conservation Plan, Natural Community Conservation Plan, or any other relevant habitat conservation plan, and would not create divisions in any existing communities because compliance with PR 1179.1 would occur at an existing facility in a previously disturbed area which are not typically subject to Habitat or Natural Community Conservation Plans.

Conclusion

Based upon these considerations, significant biological resource impacts are not expected from implementing PR 1179.1. Since no significant biological resource impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
V. CULTURAL AND TRIBAL CULTURAL RESOURCES. Would the project:				
a) Cause a substantial adverse change in the significance of a historical resource pursuant to CEQA Guidelines Section 15064.5?	☐	☐	☐	☑
b) Cause a substantial adverse change in the significance of an archaeological resource pursuant to CEQA Guidelines Section 15064.5?	☐	☐	☐	☑
c) Disturb any human remains, including those interred outside of dedicated cemeteries?	☐	☐	☐	☑
d) Cause a substantial adverse change in the significance of a tribal cultural resource as defined in Public Resources Code §21074, as either a site, feature, place, cultural landscape that is geographically defined in terms of the size and scope of the landscape, sacred place, or object with cultural value to a California Native American Tribe, and that is either:				
• Listed or eligible for listing in the California Register of Historical Resources, or in a local register of historical resources as defined in Public Resources Code §5020.1(k)?	☐	☐	☐	☑
• A resource determined by the lead agency, in its discretion and supported by substantial evidence, to be significant pursuant to criteria set forth in Public Resources Code §5024.1(c)? (In applying the criteria set forth in Public Resources Code §5024.1(c), the lead agency shall consider the significance of the resource to a California Native American tribe.)	☐	☐	☐	☑

Significance Criteria

Impacts to cultural resources will be considered significant if:

- The project results in the disturbance of a significant prehistoric or historic archaeological site or a property of historic or cultural significance, or tribal cultural significance to a community or ethnic or social group or a California Native American tribe.
- Unique resources or objects with cultural value to a California Native American tribe are present that could be disturbed by construction of the proposed project.
- The project would disturb human remains.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18.8 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

V. a), b), c), & d) No Impact. There are existing laws in place that are designed to protect and mitigate potential impacts to cultural resources. For example, CEQA Guidelines state that generally, a resource shall be considered "historically significant" if the resource meets the criteria for listing in the California Register of Historical Resources, which include the following:

- Is associated with events that have made a significant contribution to the broad patterns of California's history and cultural heritage;
- Is associated with the lives of persons important in our past;
- Embodies the distinctive characteristics of a type, period, region, or method of construction, or represent the work of an important creative individual, or possesses high artistic values;
- Has yielded or may be likely to yield information important in prehistory or history (CEQA Guidelines Section 15064.5).

Buildings, structures, and other potential culturally significant resources that are less than 50 years old are generally excluded from listing in the National Register of Historic Places, unless they are shown to be exceptionally important. The implementation of the proposed project would not lead to construction or the alteration of buildings located at any of the POTW facilities subject to PR 1179.1 requirements. Therefore, PR 1179.1 has no potential to cause a substantial adverse change to a historical or archaeological resource, directly or indirectly to destroy a unique paleontological resource or site or unique geologic feature, or to disturb any human remains, including those interred outside formal cemeteries. Implementing PR 1179.1 is, therefore, not anticipated to result in any activities or promote any programs that could have a significant adverse impact on cultural resources.

For the same reasons, PR 1179.1 is not expected to require physical modifications that would contribute to changes at a site, feature, place, cultural landscape, sacred place or object with cultural value to a California Native American Tribe. Furthermore, PR 1179.1 is not expected to result in a physical modification that would affect a resource determined to be eligible for inclusion or listed in the California Register of Historical Resources or included in a local register of historical resources. Similarly, PR 1179.1 is not expected to result in a physical change to a resource determined by the South Coast AQMD to be significant to any tribe. For these reasons, PR 1179.1 is not expected to cause any substantial adverse change in the significance of a tribal cultural resource as defined in Public Resources Code Section 21074.

As part of releasing this CEQA document for public review and comment, the South Coast AQMD also provided a formal notice of the proposed project 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 proposed project.

In the event that a Tribe submits a written request for consultation during this 30-day period, the South Coast AQMD will initiate a consultation with the Tribe within 30 days of receiving the request in accordance with Public Resources Code Section 21080.3.1(b). Consultation ends when either: 1) both parties agree to measures to avoid or mitigate a significant effect on a Tribal Cultural Resource and agreed upon mitigation measures shall be recommended for inclusion in the environmental document [see Public Resources Code Section 21082.3(a)]; or, 2) either party, acting in good faith and after reasonable effort, concludes that mutual agreement cannot be reached. [Public Resources Code Section 21080.3.2(b)(1)-(2) and Section 21080.3.1(b)(1)].

Conclusion

Based upon these considerations, significant adverse cultural and tribal cultural resources impacts are not expected from implementing PR 1179.1. Since no significant cultural and tribal cultural resources impacts were identified, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
VI.	**ENERGY.** Would the project:				
a)	Conflict with or obstruct adopted energy conservation plans, a state or local plan for renewable energy, or energy efficiency?	☐	☐	☐	☑
b)	Result in the need for new or substantially altered power or natural gas utility systems?	☐	☐	☑	☐
c)	Create any significant effects on local or regional energy supplies and on requirements for additional energy?	☐	☐	☑	☐
d)	Create any significant effects on peak and base period demands for electricity and other forms of energy?	☐	☐	☑	☐
e)	Comply with existing energy standards?	☐	☐	☐	☑
f)	Result in potentially significant environmental impact due to wasteful, inefficient, or unnecessary consumption of energy resources, during project construction or operation?	☐	☐	☐	☑
g)	Require or result in the relocation or construction of new or expanded electric power, natural gas or telecommunication facilities, the construction or relocation of which could cause significant environmental effects?	☐	☐	☐	☑

Significance Criteria

Impacts to energy resources will be considered significant if any of the following criteria are met:

- The project conflicts with adopted energy conservation plans or standards.
- The project results in substantial depletion of existing energy resource supplies.
- An increase in demand for utilities impacts the current capacities of the electric and natural gas utilities.
- The project uses energy resources in a wasteful and/or inefficient manner.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

VI. a), e) f) & g) No Impact. All 30 POTW facilities subject to PR 1179 utilize digester gas or a blend of digester gas as fuel for operating various combustion equipment. The digester gas is produced from processing decomposing organic solids in sewage and wastewater. In the event excess digester gas is produced at the POTW and equipment that ordinarily utilizes digester gas is either operating at its maximum capacity or is otherwise unavailable, the excess digester gas is routed to and combusted in a flare. Due to a potential cost savings, utilizing digester gas that is produced on-site as a fuel source for combustion equipment is considered a beneficial use and is preferred over flaring, especially if relying on purchased natural gas provided by a local utility to provide fuel for POTW combustion equipment could potentially be avoided. Implementation of PR 1179.1 would not change the existing use of digester gas or digester gas blends as an energy source to fuel the various combustion equipment operating at POTW facilities. Further, PR 1179.1 will not change how facilities process and handle excess digester gas. For these reasons, PR 1179.1 is not expected to conflict with any adopted energy conservation plans or violate any energy conservation standards because the 30 POTW facilities subject to PR 1179.1 would be expected to continue implementing any existing energy conservation plans that are currently in place regardless of whether PR 1179.1 is implemented. For these reasons, PR 1179.1 is not expected to conflict with energy conservation plans or existing energy standards, or use non-renewable resources in a wasteful manner.

None of the POTW facilities subject to PR 1179.1 will need to make any physical modifications to comply with the emission reduction requirements in PR 1179.1 because they currently operate pursuant to South Coast AQMD permits which contain applicable emission limits. Only one POTW facility that operates three turbines rated greater than 0.3 MW would be expected to make some relatively minor operational changes in order to achieve the 18.8 ppm NOx emission limit to comply with PR 1179.1. To specifically reduce NOx emissions, one facility would need to increase their total water usage by 24,000 gallons per day as part of their existing water injection process for their three turbines. Since the facility has its own supply of water and the increase in water injection can be employed immediately by adjusting the water input flow rate, additional water usage would not require physical modifications to existing piping or water pumping systems. Thus, no additional construction at this facility would be expected. For these reasons, implementation of PR 1179.1 would not require or result in the relocation or construction of new or expanded electric power, natural gas or telecommunication facilities, the construction or relocation of which could cause significant environmental effects.

VI. b), c), & d) Less than Significant. Of the 30 POTW facilities subject to PR 1179.1, none will need additional electricity or other forms of energy in order to implement the proposed project. Thus, PR 1179.1 will not be expected to create any significant effects on peak and base period demands for electricity and other forms of energy.

One POTW facility intends to increase the quantity of water injected into its three large turbines in order to meet the proposed NOx emission limit, and this will slightly reduce the energy output of the three turbines by 400 kilowatts (kW) per year. The average gross energy output from the existing turbines is 20.4 megawatts, but after injecting water, it'll reduce to 20.0 megawatts which would result in a 2% decrease in efficiency over the course of one year. Because the digester fuel combusted in the three large turbines is produced on-site and the turbines produce electricity which provide on-site power elsewhere within the facility, this minimal energy penalty would not trigger the need for a utility to provide additional electricity to the affected facility or require new or substantially altered power systems since any additional energy needed can be provided from existing supplies. Thus, implementation of PR 1179.1 would be expected to result in less than significant energy impacts.

Diesel-fueled source testing support trucks and gasoline-fueled source testing worker vehicles will travel to two facilities to conduct 10 source tests with a frequency pursuant to subdivision (e) in the proposed rule. The analysis assumes that on a peak day there will be two gasoline-fueled light duty work vehicles and two diesel-fueled medium duty support vehicles used to conduct source testing. The analysis assumes that each source testing trip will be 40 miles round trip. The analysis assumes an average fuel economy of 21 mpg for gasoline-fueled passenger vehicles and 10 mpg for diesel-fueled source testing trucks. The projected fuel demand during operation is presented in Table 2-4.

Table 2-4
Annual Total Projected Fuel Usage for Operation Activities

	Diesel	**Gasoline**
Projected Operational Energy Use (gal/yr)[a]	8	4
Year 2017 South Coast AQMD Jurisdiction Estimated Fuel Demand (gal/yr)[b]	775,000,000	7,086,000,000
Total Increase Above Baseline	0.00000%	0.000000%
Significance Threshold	1%	1%
Significant?	**No**	**No**

Notes:

a) Estimated peak fuel usage from operational activities. Diesel usage estimates are based on source test trips. Gasoline usage estimates are derived from source test trips.

b) California Annual Retail Fuel Outlet Report Results (CEC-A15) Spreadsheets, 2017 California Energy Commission (http://www.energy.ca.gov/almanac/transportation_data/gasoline/piira_retail_survey.html). [Accessed June 21, 2019.]

Operational gasoline truck usage is only expected to consume about 4 gallons of gasoline, approximately 0.00000% of the annual gasoline supply. Diesel operated heavy duty truck usage could consume 8 gallons of diesel, which is only 0.00000% of the annual diesel supply. The projected increased use of gasoline and diesel fuels as a result of implementing PR 1179.1 are well below the South Coast AQMD significance threshold for fuel supply. Thus, no significant adverse impact on fuel supplies would be expected during operation.

Further, since minimal amounts of fuels such as natural gas, gasoline, and diesel would be needed to implement the operational changes that may occur as part of implementing PR 1179.1, no change to existing local or regional natural gas, gasoline, and diesel supplies and usage would be expected to occur and there would be no need for new or substantially altered natural gas utility systems.

Conclusion

Based upon these considerations, significant adverse energy impacts are not expected from implementing PR 1179.1. Since no significant energy impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
VII. GEOLOGY AND SOILS. Would the project:				
a) Directly or indirectly cause potential substantial adverse effects, including the risk of loss, injury, or death involving:				
• Rupture of a known earthquake fault, as delineated on the most recent Alquist-Priolo Earthquake Fault Zoning Map issued by the State Geologist for the area or based on other substantial evidence of a known fault?	☐	☐	☐	☑
• Strong seismic ground shaking?	☐	☐	☐	☑
• Seismic-related ground failure, including liquefaction?	☐	☐	☐	☑
• Landslides?	☐	☐	☐	☑
b) Result in substantial soil erosion or the loss of topsoil?	☐	☐	☐	☑
c) Be located on a geologic unit or soil that is unstable or that would become unstable as a result of the project, and potentially result in on- or off-site landslide, lateral spreading, subsidence, liquefaction or collapse?	☐	☐	☐	☑
d) Be located on expansive soil, as defined in Table 18-1-B of the Uniform Building Code (1994), creating substantial direct or indirect risks to life or property?	☐	☐	☐	☑
e) Have soils incapable of adequately supporting the use of septic tanks or alternative wastewater disposal systems where sewers are not available for the disposal of wastewater?	☐	☐	☐	☑
f) Directly or indirectly destroy a unique paleontological resource or site or unique geological feature?	☐	☐	☐	☑

Significance Criteria

Impacts on the geological environment will be considered significant if any of the following criteria apply:

- Topographic alterations would result in significant changes, disruptions, displacement, excavation, compaction or over covering of large amounts of soil.
- Unique geological resources (paleontological resources or unique outcrops) are present that could be disturbed by the construction of the proposed project.
- Exposure of people or structures to major geologic hazards such as earthquake surface rupture, ground shaking, liquefaction or landslides.
- Secondary seismic effects could occur which could damage facility structures, e.g., liquefaction.
- Other geological hazards exist which could adversely affect the facility, e.g., landslides, mudslides.
- Unique paleontological resources or sites or unique geologic features are present that could be directly or indirectly destroyed by the proposed project.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

VII. a), b), c) and f) No Impact. All 30 POTWs are existing facilities located industrial areas and none will need to make any physical modifications changes to comply with the emission reduction requirements in PR 1179.1 because they currently operate pursuant to South Coast AQMD permits which contain applicable emission limits. Only one POTW facility that operates three turbines rated greater than 0.3 MW would be expected to make some relatively minor operational changes in order to achieve the 18.8 ppm NOx emission limit to comply with PR 1179.1. To specifically reduce NOx emissions, one facility would need to increase their total water usage by 24,000 gallons per day as part of their existing water injection process for their three turbines. The additional water usage would not require physical modifications to existing piping or water pumping systems. Thus, no additional construction at the facility would be expected. Further, because the increased water injection activities will occur within equipment piping, all within the boundaries of the affected facility, and no other facilities will be expected to make any physical modifications or operational changes in order to comply with PR 1179.1, implementation of the proposed project is not expected to disturb any soil or geological formations. Therefore, PR 1179.1 would not directly or indirectly cause potential adverse effects or result in the substantial erosion or loss of topsoil. Also, since implementation of PR 1179.1 will have no effect on the soil types present at the affected facilities, the existing soils will not be made further susceptible to expansion or liquefaction. Furthermore, PR 1179.1 will not create any new conditions that would cause subsidence landslides, or alter unique geologic features at any of the 30 POTW facilities. Thus, the proposed project would not be expected to increase or exacerbate any existing risks associated with soils at the affected facility locations. Implementation of PR 1179.1 would not involve re-locating any facility onto a geologic unit or soil that is unstable or that would become unstable as a result of the project; therefore, it would not be expected to potentially result in on-or off-site landslide, lateral spreading, subsidence, liquefaction, or collapse. Finally, because PR 1179.1 is not expected to require soil to be disturbed, implementation of the proposed project is not expected to directly or indirectly destroy a unique paleontological resource or site or unique geological feature. No impacts are anticipated.

VII. d) & e) No Impact. The 30 facilities subject to PR 1179.1 are POTWs which treat sewage and wastewater and implementation of PR 1179.1 would not alter how these facilities conduct their existing operations. Further, PR 1179.1 does not contain any provision that would require the installation of septic tanks or other alternative wastewater disposal systems since all 30 facilities have existing sanitary systems that are connected to the local sewer systems. Therefore, no persons or property will be exposed to new impacts related to expansive soils or soils incapable of supporting water disposal. Thus, the implementation of PR 1179.1 will not adversely affect soils associated with a installing a new septic system or alternative wastewater disposal system or modifying an existing sewer.

Conclusion

Based upon these considerations, significant adverse geology and soils impacts are not expected from the implementation of PR 1179.1. Since no significant geology and soils impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
VIII. HAZARDS AND HAZARDOUS MATERIALS. Would the project:				
a) Create a significant hazard to the public or the environment through the routine transport, use, or disposal of hazardous materials?	☐	☐	☐	☑
b) Create a significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment?	☐	☐	☐	☑
c) Emit hazardous emissions, or handle hazardous or acutely hazardous materials, substances, or waste within one-quarter mile of an existing or proposed school?	☐	☐	☐	☑
d) Be located on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code §65962.5 and, as a result, would create a significant hazard to the public or the environment?	☐	☐	☐	☑
e) For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, would the project result in a safety hazard for people residing or working in the project area?	☐	☐	☐	☑
f) Impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan?	☐	☐	☐	☑
g) Significantly increased fire hazard in areas with flammable materials?	☐	☐	☑	☐

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.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

VIII. a) & b) No Impact. All 30 POTWs subject to PR 1179.1 are existing facilities located industrial areas and none will need to make any physical modifications to comply with the emission reduction requirements in PR 1179.1 because they currently operate pursuant to South Coast AQMD permits which contain applicable emission limits. Only one POTW facility that operates three turbines rated greater than 0.3 MW would be expected to make some relatively minor operational changes in order to achieve the 18.8 ppm NOx emission limit to comply with PR 1179.1. To specifically reduce NOx emissions, one facility would need to increase their total water usage by 24,000 gallons per day as part of their existing water injection process for their three turbines. The additional water usage would not require physical modifications to existing piping or water pumping systems and the water does not utilize any hazardous materials. Thus, no additional construction at the facility would be expected. Further, while the affected facilities may currently have existing activities that involve the routine transport, use, or disposal of hazardous materials, implementation of PR 1179.1 would not alter these existing activities or create a new significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment.

VIII. c) No Impact. As explained in Section VIII. a) and b), while the affected facilities may currently have existing activities that involve the routine transport, use, or disposal of hazardous materials, implementation of PR 1179.1 would not alter these existing activities or create a new significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment. Thus, even though some of the affected facilities may be located within one-quarter mile of an existing or newly proposed school, PR 1179.1 does not include new requirements that would cause any of the affected facilities to generate new hazardous emissions, or change how hazardous or acutely hazardous materials, substances, or waste is currently handled.

VIII. d) No Impact. Government Code Section 65962.5 refers to hazardous waste handling practices at facilities subject to the Resources Conservation and Recovery Act (RCRA). While two of the 30 facilities, presented in Appendix B are identified on lists of California Department of Toxics Substances Control hazardous waste facilities per Government Code Section 65962.5, PR 1179.1 contains no requirements that interfere with existing hazardous waste management programs since facilities handling hazardous waste would be expected to continue to manage any and all hazardous materials and hazardous waste, in accordance with applicable federal, state, and local rules and regulations. Therefore, compliance with PR 1179.1 would neither change any existing hazards to public or environment nor create any new significant hazards to the public or environment.

VIII. e) No Impact. Federal Aviation Administration regulation, 14 CFR Part 77 – Safe, Efficient Use and Preservation of the Navigable Airspace, provide information regarding the types of projects that may affect navigable airspace. Projects may adversely affect navigable airspace if they involve construction or alteration of structures greater than 200 feet above ground level within a specified distance from the nearest runway or objects within 20,000 feet of an airport or seaplane base with at least one runway more than 3,200 feet in length and the object would exceed a slope of 100:1 horizontally (100 feet horizontally for each one foot vertically from the nearest point of the runway). Even if any of the affected facilities are located within an airport land use plan or, within two miles of a public airport or public use airport, PR 1179.1 will not result in the alteration of any buildings or structures. Therefore, implementation of PR 1179.1 is not expected to increase or create any new safety hazards to peoples working or residing in the vicinity of public/private airports.

VIII. f) No Impact. Health and Safety Code 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:

- Identification of individuals who are responsible for various actions, including reporting, assisting emergency response personnel and establishing an emergency response team;
- Procedures to notify the administering agency, the appropriate local emergency rescue personnel, and the California Office of Emergency Services;
- Procedures to mitigate a release or threatened release to minimize any potential harm or damage to persons, property or the environment;
- Procedures to notify the necessary persons who can respond to an emergency within the facility;
- Details of evacuation plans and procedures;
- Descriptions of the emergency equipment available in the facility;

- Identification of local emergency medical assistance; and,
- Training (initial and refresher) programs for employees in:
  1. The safe handling of hazardous materials used by the business;
  2. Methods of working with the local public emergency response agencies;
  3. The use of emergency response resources under control of the handler;
  4. 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 conjunction with the California Office of Emergency Services, 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.

Emergency response plans are typically prepared in coordination with the local city or county emergency plans to ensure the safety of not only the public (surrounding local communities), but the facility employees as well. The proposed project would not impair the implementation of, or physically interfere with any adopted emergency response plans or emergency evacuation plans that may be in place at the existing facility because PR 1179.1 does not require the new or altered use of hazardous materials and would not involve any alterations to buildings or structures.

VIII. g) Less Than Significant Impact. The Uniform Fire Code and Uniform Building Code set standards intended to minimize risks from flammable or otherwise hazardous materials. Local jurisdictions are required to adopt the uniform codes or comparable regulations. Local fire agencies require permits for the use or storage of hazardous materials and permit modifications for proposed increases in their use. Permit conditions depend on the type and quantity of the hazardous materials at the facility. Permit conditions may include, but are not limited to, specifications for sprinkler systems, electrical systems, ventilation, and containment. The fire departments make annual business inspections to ensure compliance with permit conditions and other appropriate regulations. Further, businesses are required to report increases in the storage or use of flammable and otherwise hazardous materials to local fire departments. Local fire departments ensure that adequate permit conditions are in place to protect against the potential risk of upset. PR 1179.1 would not change the existing requirements and permit conditions for the proper handling of flammable materials at the affected facility. Further, PR 1179.1 does not contain any requirements that would prompt facility owners/operators to begin using new flammable materials. In addition, the National Fire Protection Association has special designations for deflagrations (e.g., explosion prevention) when using materials that may be explosive and PR 1179.1 would not alter how the affected facilities fire prevention plans.

Conclusion

Based upon these considerations, significant adverse hazards and hazardous materials impacts are not expected from implementing PR 1179.1. Since no significant hazards and hazardous materials impacts were identified, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
IX.	**HYDROLOGY AND WATER QUALITY.** Would the project:				
a)	Violate any water quality standards, waste discharge requirements, or otherwise substantially degrade surface or ground water quality?	☐	☐	☐	☑
b)	Substantially decrease groundwater supplies or interfere substantially with groundwater recharge such that the project may impede sustainable groundwater management of the basin?	☐	☐	☐	☑
c)	Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river or through the addition of impervious surfaces, in a manner which would:				
	• Result in substantial erosion or siltation on- or off-site?	☐	☐	☐	☑
	• Substantially increase the rate or amount of surface runoff in a manner which would result in flooding on- or off-site?	☐	☐	☐	☑
	• Create or contribute runoff water which would exceed the capacity of existing or planned storm water drainage systems or provide substantial additional sources of polluted runoff?	☐	☐	☐	☑
	• Impede or redirect flood flows?	☐	☐	☐	☑
d)	In flood hazard, tsunami, or seiche zones, risk release of pollutants due to project inundation?	☐	☐	☐	☑
e)	Conflict with or obstruct implementation of a water quality control plan or sustainable groundwater management plan?	☐	☐	☐	☑

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
f)	Require or result in the relocation or construction of new or expanded water, wastewater treatment or storm water drainage, facilities or new storm water drainage facilities, the construction or relocation of which could cause significant environmental effects?	☐	☐	☐	☑
g)	Have sufficient water supplies available to serve the project and reasonably foreseeable future development during normal, dry and multiple dry years?	☐	☐	☑	☐
h)	Result in a determination by the wastewater treatment provider which serves or may serve the project that it has adequate capacity to serve the project's projected demand in addition to the provider's existing commitments?	☐	☐	☐	☑

Significance Criteria

Potential impacts on water resources will be considered significant if any of the following criteria apply:

<u>Water Demand:</u>

- 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 project increases demand for total water by more than five million gallons per day.

<u>Water Quality:</u>

- The project will cause degradation or depletion of ground water resources substantially affecting current or future uses.
- The project will cause the degradation of surface water substantially affecting current or future uses.
- The project will result in a violation of National Pollutant Discharge Elimination System (NPDES) permit requirements.
- The capacities of existing or proposed wastewater treatment facilities and the sanitary sewer system are not sufficient to meet the needs of the project.

- The project results in substantial increases in the area of impervious surfaces, such that interference with groundwater recharge efforts occurs.
- The project results in alterations to the course or flow of floodwaters.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

IX. a), b), e), f), & h) No Impact. Of the 30 facilities that will be subject to PR 1179.1, only one facility that operates three large turbines which utilize water injection as a NOx emission control method will need to use additional water in order to achieve the 18.8 ppm NOx emission limit. The type of water that is used for water injection in the turbines is <u>demineralized</u> ~~deionized~~ water. Since the POTW is by design, a wastewater treatment facility, the facility has sufficient supplies of water that it is capable of treating ~~and deionizing~~ to remove contaminants prior to injecting it into the turbines to prevent build-up of calcium and other minerals. The facility estimated that an additional 8,000 gallons of <u>demineralized</u> ~~deionized~~ water per day per turbine for a total of 24,000 gallons per day would be needed to supplement their existing water injection activities.

Since the turbines currently employ water injection for NOx emission control purposes, increasing the amount of water injected into the turbines is a matter of adjusting the flow rate and is expected to occur as part of normal day-to-day operations of the turbines. The facility has provided the following additional information regarding the anticipated increase in water injected into the turbines:

- The facility has its own supply of water and the increase in water injection can be employed immediately by adjusting the water input flow rate;
- No groundwater is used by this facility for the purposes of water injection into turbines because groundwater contains sand and other particles or debris which is not suitable; and
- Due to the high temperature in the combustion chamber, all of the injected water is vaporized such that there is no wastewater stream.

Since no wastewater stream is generated from the water injection process, the proposed project would not be expected to: 1) violate any water quality standards, waste discharge requirements of the applicable Regional Water Quality Control Board, or otherwise substantially degrade surface or ground water quality; 2) require or result in the relocation or construction of new or expanded water, wastewater treatment or storm water drainage, facilities or new storm water drainage facilities; and 3) give any cause for the POTW, which is the wastewater treatment provider, to question or evaluate whether adequate wastewater capacity exists post-project.

Further, since no groundwater will be utilized to satisfy the increased demand of water for injection purposes, PR 1179.1 will not: 1) substantially decrease groundwater supplies or interfere substantially with groundwater recharge or impede sustainable groundwater management of the basin; and 2) conflict with or obstruct implementation of a water quality control plan or sustainable groundwater management plan.

IX. g) Less than Significant Impact. Of the 30 facilities that will be subject to PR 1179.1, only one facility that operates three large turbines which utilize water injection as a NOx emission control method will need to use additional water in order to achieve the 18.8 ppm NOx emission limit. The type of water that is used for water injection in the turbines is demineralized ~~deionized~~ water. Since the POTW is by design, a wastewater treatment facility, the facility has sufficient supplies of water that it is capable of treating ~~and deionizing~~ to remove contaminants prior to injecting it into the turbines to prevent build-up of calcium and other minerals. The facility estimated that an additional 8,000 gallons of demineralized ~~deionized~~ water per day per turbine for a total of 24,000 gallons per day would be needed to supplement their existing water injection activities. Since an increased use of 24,000 gallons of water per day is less than the significance threshold of 262,820 gallons per day for potable water and 5,000,000 gallons per day of total water, the proposed project will result in less than significant water demand impacts. The water demand is relatively minor when compared to the significance thresholds for water usage, and is expected to be well within the facility's existing supporting infrastructure to process, treat, and supply large quantities of water. Similarly, because the POTW has existing water supplies which are sufficient to support the implementation of additional water injection for NOx emission control purposes, the availability of sufficient water supplies to serve the project and reasonably foreseeable future development during normal, dry and multiple dry years is not expected to be significantly impacted by PR 1179.1. Further, PR 1179.1 is a rule aimed to reduce emissions from combustion equipment located at existing wastewater treatment facilities and the affected facility has the adequate capacity to serve the proposed project's demand in addition to the provider's existing commitments.

IX. c) No Impact. Implementation of PR 1179.1 would not be expected to substantially alter the existing drainage patterns of any POTW facility or areas beyond what currently exists at each site. Because all of the POTW facilities are sited in urban industrial areas, PR 1179.1 will not cause any changes where streams or rivers would flow through any of the POTW facilities. Thus, PR 1179.1 would not cause an alteration to the course or flow of a stream or river. In addition, PR 1179.1 would not create new or contribute to existing runoff water which would exceed the capacity of existing or planned storm water drainage systems or provide substantial additional sources of polluted runoff, because PR 1179.1 does not contain any requirements that would change existing drainage patterns or the procedures for how surface runoff is handled.

IX. d) No Impact. As previously explained in Section IV – Biological Resources, PR 1179.1 would not require new development to occur. The implementation of PR 1179.1 would not require construction, therefore, PR 1179.1 would not be expected to expose people or structures to a significant risk of loss, injury, or death involving flooding as a result of the failure of a levee or dam, or inundation by seiche, tsunami, or mudflow because any flood event of this nature would be part of the existing setting or topography that is present for reasons unrelated to PR 1179.1. Similarly, there is no risk of release of pollutants due to inundation as a result of PR 1179.1.

Conclusion
Based upon these considerations, significant adverse hydrology and water quality impacts are not expected from implementing PR 1179.1. Since no significant hydrology and water quality impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
X. LAND USE AND PLANNING. Would the project:				
a) Physically divide an established community?	☐	☐	☐	☑
b) Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project (including, but not limited to the general plan, specific plan, local coastal program or zoning ordinance) adopted for the purpose of avoiding or mitigating an environmental effect?	☐	☐	☐	☑

Significance Criteria

Land use and planning impacts will be considered significant if the project conflicts with the land use and zoning designations established by local jurisdictions.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

X. a) & b) No Impact. PR 1179.1 does not require the construction of new buildings or the alteration of existing buildings. For this reason, implementation of PR 1179.1 is not expected to physically divide an established community. Therefore, no impacts are anticipated.

Further, land use and other planning considerations are determined by local governments and PR 1179.1 does not alter any land use or planning requirements. PR 1179.1 would regulate emissions from combustion equipment operating at existing POTW facilities without requiring any alterations to existing buildings or structures. Thus, implementation of PR 1179.1 would not be expected to affect or conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project (including, but not limited to the general plan, specific plan, local coastal program or zoning ordinance) adopted for the purpose of avoiding or mitigating an environmental effect.

Conclusion

Based upon these considerations, significant adverse land use and planning impacts are not expected from implementing PR 1179.1. Since no significant land use and planning impacts were identified, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XI.	**MINERAL RESOURCES.** Would the project:				
a)	Result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state?	☐	☐	☐	☑
b)	Result in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan?	☐	☐	☐	☑

Significance Criteria

Project-related impacts on mineral resources will be considered significant if any of the following conditions are met:

- The project would result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state.
- The proposed project results in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

XI. a) & b) No Impact. There are no provisions in PR 1179.1 that would result in the loss of availability of a known mineral resource of value to the region and the residents of the state, or of a locally-important mineral resource recovery site delineated on a local general plan, specific plant, or other land use plant. The proposed project would not require construction activities or place new demand on mineral resources in order to reduce emissions from combustion equipment operating at POTW facilities. Therefore, no significant adverse mineral resources impacts are expected from implementing PR 1179.1 are anticipated.

Conclusion

Based upon these considerations, significant adverse mineral resource impacts are not expected from implementing PR 1179.1. Since no significant mineral resource impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XII. NOISE. Would the project result in:				
a) Generation of a substantial temporary or permanent increase in ambient noise levels in the vicinity of the project in excess of standards established in the local general plan or noise ordinance, or applicable standards of other agencies?	☐	☐	☐	☑
b) Generation of excessive groundborne vibration or groundborne noise levels?	☐	☐	☐	☑
c) For a project located within the vicinity of a private airstrip or an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, would the project expose people residing or working in the project area to excessive noise levels?	☐	☐	☐	☑

Significance Criteria

Noise impact will be considered significant if:

- Construction noise levels exceed the local noise ordinances or, if the noise threshold is currently exceeded, project noise sources increase ambient noise levels by more than three decibels (dBA) at the site boundary. Construction noise levels will be considered significant if they exceed federal Occupational Safety and Health Administration (OSHA) noise standards for workers.
- The proposed project operational noise levels exceed any of the local noise ordinances at the site boundary or, if the noise threshold is currently exceeded, project noise sources increase ambient noise levels by more than three dBA at the site boundary.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

XII. a), b) & c) No Impact. All of the 30 facilities affected by PR 1179.1 are located in urbanized, industrial areas and the existing noise environment at these facilities is typically dominated by noise from existing equipment on-site, vehicular traffic around the facilities, and trucks entering and exiting facility premises. Further, none of the facilities and their various existing combustion equipment will need to make any physical modifications to comply with the emission reduction requirements in PR 1179.1 because they currently operate pursuant to South Coast AQMD permits which contain applicable emission limits. Only one POTW facility that operates three turbines rated greater than 0.3 MW would be expected to make some relatively minor operational changes in order to achieve the 18.8 ppm NOx emission limit to comply with PR 1179.1. To specifically reduce NOx emissions, one facility would need to increase their total water usage by 24,000 gallons per day as part of their existing water injection process for their three turbines. Thus, no additional construction and associated noise-producing construction equipment and vehicles would be needed at any of the affected facilities. As such, no changes to the existing overall noise profiles of the affected facilities are expected to occur and noise levels would be expected to stay within existing baseline noise levels from day-to-day operations at each facility.

Finally, as explained in Section VIII. e), even if any of the affected facilities are located within an airport land use plan or, within two miles of a public airport or public use airport, PR 1179.1 will not result in the alteration of any buildings or structures requiring construction and associated noise-producing construction equipment and vehicles. Thus, persons residing or working within two miles of a public airport or private airstrip would not be exposed to excessive noise levels if PR 1179.1 is implemented.

Conclusion

Based upon these considerations, significant adverse noise impacts are not expected from the implementing PR 1179.1. Since no significant noise impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XIII. POPULATION AND HOUSING. Would the project:				
a) Induce substantial growth in an area either directly (for example, by proposing new homes and businesses) or indirectly (e.g., through extension of roads or other infrastructure)?	☐	☐	☐	☑
b) Displace substantial numbers of people or existing housing, necessitating the construction of replacement housing elsewhere?	☐	☐	☐	☑

Significance Criteria

Impacts of the proposed project on population and housing will be considered significant if the following criteria are exceeded:

- The demand for temporary or permanent housing exceeds the existing supply.
- The proposed project produces additional population, housing or employment inconsistent with adopted plans either in terms of overall amount or location.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

XIII. a) & b) No Impact. PR 1179.1 is designed to establish emission limits that are representative of BARCT for NOx, CO, and VOC emissions from engines and BARCT for NOx and CO emissions from boilers/steam generators, process heaters, and turbines located at POTWs that were not addressed in other source-specific rules. Of the 30 facilities that will be subject to PR 1179.1 after adoption, none of the facilities will need to make any physical modifications changes to comply with the emission reduction requirements in PR 1179.1 because their combustion equipment currently operate pursuant to South Coast AQMD permits which contain applicable emission limits. Only one POTW facility that operates three large turbines (each are rated greater than 0.3 MW) is expected to make relatively minor operational changes related to increasing the amount of water injected into the combustion chambers in order to achieve the 18.8 ppm NOx emission limit to comply with PR 1179.1. The facility has indicated that they can achieve this NOx emission limit by increasing the amount of water that is currently injected into the combustion chamber as a NOx emission reduction measure without having to either install additional NOx emission control equipment such as SCR or replace their turbines. Thus, no construction activities are expected to occur. Since the turbines currently employ water injection for NOx emission control purposes, increasing the amount of water injected into the turbines is a matter of adjusting the flow rate and is expected to occur as part of normal day-to-day operations of the turbines. The facility has indicated that injecting additional water may require increased maintenance due to erosion and wear on turbine equipment, but the maintenance can be conducted by existing employees so no additional workers or vendors will be needed. Thus, PR 1179.1 is not expected to involve the relocation of individuals, require new housing or commercial facilities, or change the distribution of the population. Maintenance activities resulting from PR 1179.1 would also not be expected to result in the need for additional employees because existing personnel are available to perform the required day-to-day maintenance. PR 1179.1 is not anticipated to not result in changes in population densities, population distribution, or induce significant growth in population.

Conclusion

Based upon these considerations, significant adverse population and housing impacts are not expected from implementing PR 1179.1. Since no significant population and housing impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XIV. PUBLIC SERVICES. Would the project result in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, need for new or physically altered governmental facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response times or other performance objectives for any of the following public services:				
a) Fire protection?	☐	☐	☐	☑
b) Police protection?	☐	☐	☐	☑
c) Schools?	☐	☐	☐	☑
d) Parks?	☐	☐	☐	☑
e) Other public facilities?	☐	☐	☐	☑

Significance Criteria

Impacts on public services will be considered significant if the project results in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, or the need for new or physically altered government facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response time, or other performance objectives.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

XIV. a) & b) No Impact. PR 1179.1 is designed to establish emission limits that are representative of BARCT for NOx, CO, and VOC emissions from engines and BARCT for NOx and CO emissions from boilers/steam generators, process heaters, and turbines located at POTWs that were not addressed in other source-specific rules. Of the 30 facilities that will be subject to PR 1179.1 after adoption, none of the facilities will need to make any physical modifications to comply with the emission reduction requirements in PR 1179.1 because their combustion equipment currently operate pursuant to South Coast AQMD permits which contain applicable emission limits. Only one POTW facility that operates three large turbines (each are rated greater than 0.3 MW) is expected to make some relatively minor operational changes related to increasing the amount of water injected into the combustion chambers in order to achieve the 18.8 ppm NOx emission limit to comply with PR 1179.1. The facility has indicated that they can achieve this NOx emission limit by increasing the amount of water that is currently injected into the combustion chamber as a NOx emission reduction measure without having to either install additional NOx emission control equipment such as SCR or replace or retrofit their turbines. Thus, no construction activities are expected to occur. Since the turbines currently employ water injection for NOx emission control purposes, increasing the amount of water injected into the turbines is a matter of adjusting the flow rate and is expected to occur as part of normal day-to-day operations of the turbines. The facility has indicated that injecting additional water may require increased maintenance due to erosion and wear on turbine equipment but the maintenance can be conducted by existing employees so no additional workers or vendors will be needed. Further, injecting additional water is not expected to pose a safety issue requiring the support of public service personnel. Thus, implementation of PR 1179.1 is not expected to substantially alter or increase the need or demand for additional public services (e.g., fire and police departments and related emergency services, etc.) above current levels, so no significant impact to these existing services is anticipated.

XIV. c), d), & e) No Impact. As explained in Section XIII. a) and b), PR 1179.1 is not anticipated to generate any significant effects, either direct or indirect, on the population or population distribution within South Coast AQMD's jurisdiction as no additional workers are anticipated to be needed in order to comply with PR 1179.1. Because PR 1179.1 is not expected to induce substantial population growth in any way, and because the local labor pool (e.g., workforce) would remain the same since PR 1179.1 would not trigger changes to current employment levels, no additional schools would need to be constructed as a result of implementing PR 1179.1. Therefore, since no substantial increase in local population would be anticipated as a result of implementing PR 1179.1, there would be no corresponding impacts to local schools or parks and there would be no corresponding need for new or physically altered public facilities in order to maintain acceptable service ratios, response times, or other performance objectives. Therefore, no impacts would be expected to schools, parks, or other public facilities.

Conclusion

Based upon these considerations, significant adverse public services impacts are not expected from implementing PR 1179.1. Since no significant public services impacts were identified, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XV.	**RECREATION.**				
a)	Would the project increase the use of existing neighborhood and regional parks or other recreational facilities such that substantial physical deterioration of the facility would occur or be accelerated?	☐	☐	☐	☑
b)	Does the project include recreational facilities or require the construction or expansion of recreational facilities that might have an adverse physical effect on the environment or recreational services?	☐	☐	☐	☑

Significance Criteria

Impacts to recreation will be considered significant if:

- The project results in an increased demand for neighborhood or regional parks or other recreational facilities.
- The project adversely affects existing recreational opportunities.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

XV. a) & b) No Impact. As previously explained in Section XIII – Population and Housing, PR 1179.1 is not expected to affect population growth or distribution within the South Coast AQMD's jurisdiction because no additional workers are needed to implement PR 1179.1 at the affected facilities. Thus, PR 1179.1 will have no effect on the existing labor pool supply in the local Southern California area. As such, PR 1179.1 is not anticipated to generate any significant adverse effects, either indirectly or directly on population growth within the South Coast AQMD's jurisdiction or population distribution, thus no additional demand for recreational facilities would be expected. PR 1179.1 would not be expected to affect recreation in any way because PR 1179.1 would not increase the demand for or use of existing neighborhood and regional parks or other recreational facilities or require the construction of new or expansion of existing recreational facilities that might have an adverse physical modification or effect on the environment because it would not directly or indirectly increase or redistribute population.

Conclusion

Based upon these considerations, significant adverse recreation impacts are not expected from implementing PR 1179.1. Since no significant recreation impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XVI. SOLID AND HAZARDOUS WASTE. Would the project:				
a) Be served by a landfill with sufficient permitted capacity to accommodate the project's solid waste disposal needs?	☐	☐	☑	☐
b) Comply with federal, state, and local statutes and regulations related to solid and hazardous waste?	☐	☐	☐	☑

Significance Criteria

The proposed project impacts on solid and hazardous waste will be considered significant if the following occurs:

- The generation and disposal of hazardous and non-hazardous waste exceeds the capacity of designated landfills.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

XVI. a) Less Than Significant Impact. PR 1179.1 is designed to establish emission limits that are representative of BARCT for NOx, CO, and VOC emissions from engines and BARCT for NOx and CO emissions from boilers/steam generators, process heaters, and turbines located at POTWs that were not addressed in other source-specific rules. Of the 30 facilities that will be subject to PR 1179.1 after adoption, none of the facilities will need to make any physical modifications to their various combustion equipment comply with the emission reduction requirements in PR 1179.1 because they currently operate pursuant to South Coast AQMD permits which contain applicable emission limits.

Only one POTW facility that operates three large turbines (each are rated greater than 0.3 MW) is expected to make some relatively minor operational changes related to increasing the amount of water injected into the combustion chambers in order to achieve the 18.8 ppm NOx emission limit to comply with PR 1179.1. The facility has indicated that they can achieve this NOx emission limit by increasing the amount of water that is currently injected into the combustion chamber as a NOx emission reduction measure without having to either install additional NOx emission control equipment such as SCR or replace or retrofit their turbines. Thus, no construction activities are expected to occur, which means no construction waste will be generated. Since the turbines currently employ water injection for NOx emission control purposes, increasing the amount of water injected into the turbines is a matter of adjusting the flow rate and is expected to occur as part of normal day-to-day operations of the turbines. The facility has indicated that injecting additional water may require increased maintenance due to erosion and wear on turbine equipment but the maintenance can be conducted by existing employees so no additional workers or vendors will be needed. Further, injecting additional water is not expected to generate any solid or hazardous waste requiring disposal.

Further, PR 1179.1 will not alter the quantities generated or the manner in which the existing affected facilities currently handle and dispose of their solid and hazardous waste. Thus, the existing solid and hazardous waste generation at each of the affected facilities will remain unchanged such that PR 1179.1 will have no impacts on existing permitted landfill capacities.

XVI. b) No Impact. Operators of all affected facilities subject to PR 1179.1 are required to comply with all applicable local, state, or federal waste disposal regulations, and PR 1179.1 does not contain any provisions that would weaken or alter current practices. Further, as explained in Section XVI. a), PR 1179.1 does not have any provision that would increase the disposal of solid or hazardous waste. Thus, implementation of PR 1179.1 is not expected to interfere with any affected facility's ability to comply with applicable local, state, or federal waste disposal regulations in a manner that would cause a significant adverse solid and hazardous waste impact.

Conclusion

Based upon these considerations, significant adverse solid and hazardous waste impacts are not expected from implementing PR 1179.1. Since no significant solid and hazardous waste impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XVII. TRANSPORTATION. Would the project:				
a) Conflict with a program plan, ordinance or policy addressing the circulation system, including transit, roadway, bicycle and pedestrian facilities?	☐	☐	☐	☑
b) Conflict with or be inconsistent with CEQA Guidelines Section 15064.3(b)?	☐	☐	☐	☑
c) Substantially increase hazards due to a geometric design feature (e.g., sharp curves or dangerous intersections) or incompatible uses (e.g., farm equipment)?	☐	☐	☐	☑
d) Result in inadequate emergency access?	☐	☐	☐	☑

Significance Criteria

Impacts on transportation and traffic will be considered significant if any of the following criteria apply:

- A major roadway is closed to all through traffic, and no alternate route is available.
- The project conflicts with applicable policies, plans, or programs establishing measures of effectiveness, thereby decreasing the performance or safety of any mode of transportation.
- There is an increase in traffic that is substantial in relation to the existing traffic load and capacity of the street system.
- The demand for parking facilities is substantially increased.
- Water borne, rail car or air traffic is substantially altered.
- Traffic hazards to motor vehicles, bicyclists, or pedestrians are substantially increased.
- The need for more than 350 employees.
- An increase in heavy-duty transport truck traffic to and/or from the facility by more than 350 truck round trips per day.
- Increase customer traffic by more than 700 visits per day.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

XVII. a) & b) No Impact. PR 1179.1 is designed to establish emission limits that are representative of BARCT for NOx, CO, and VOC emissions from engines and BARCT for NOx and CO emissions from boilers/steam generators, process heaters, and turbines located at POTWs that were not addressed in other source-specific rules. Of the 30 facilities that will be subject to PR 1179.1 after adoption, none will need to make any physical modifications to comply with the emission reduction requirements in PR 1179.1 because their combustion equipment currently operate pursuant to South Coast AQMD permits which contain applicable emission limits. Only one POTW facility that operates three large turbines (each are rated greater than 0.3 MW) is expected to make relatively minor operational changes related to increasing the amount of water injected into the combustion chambers in order to achieve the 18.8 ppm NOx emission limit to comply with PR 1179.1. The facility has indicated that they can achieve this NOx emission limit by increasing the amount of water that is currently injected into the combustion chamber as a NOx emission reduction measure without having to either install additional NOx emission control equipment such as SCR or replace or retrofit their turbines. Thus, no construction activities are expected to occur. Since the turbines currently employ water injection for NOx emission control purposes, increasing the amount of water injected into the turbines is a matter of adjusting the flow rate and is expected to occur as part of normal day-to-day operations of the turbines. As previously discussed in Section III – Air Quality and Greenhouse Gas Emissions, the facility has indicated that injecting additional water may require increased maintenance due to erosion and wear on turbine equipment but the maintenance can be conducted by existing employees so no additional workers or vendors, and in turn, no additional vehicle trips will be needed.

In accordance with the promulgation of SB 743 which requires analyses of transportation impacts in CEQA documents to consider a project's vehicle miles traveled (VMT) in lieu of applying a Level of Service (LOS) metric when determining significance for transportation impacts, CEQA Guidelines Section 15064.3(b)(4) gives a lead agency to use discretion to choose the most appropriate methodology to evaluate a project's VMT, allowing the metric to be expressed as a change in absolute terms, per capita, per household, or in any other measure.

No additional need for vehicle trips means that PR 1179.1 would not increase construction or operational VMT. Further, since PR 1179.1 will not create a need for additional vehicle trips, the proposed project will not conflict with or be inconsistent with CEQA Guidelines Section 15064.3(b). Similarly, because implementation of PR 1179.1 will not alter any transportation plans, PR 1179.1 will also not conflict with a program plan, ordinance, or policy addressing the circulation system, including transit, roadway, bicycle, and pedestrian facilities.

XVII. c) & d) No Impact. PR 1179.1 does not involve or require the construction of new roadways, because the focus of PR 1179.1 is to control emissions from certain combustion equipment operating at POTW facilities. Thus, no changes to current public roadway designs including a geometric design feature that could increase traffic hazards are expected. Further, PR 1179.1 is not expected to substantially increase traffic hazards or create incompatible uses at or adjacent to the affected facilities, or alter the existing long-term circulation patterns within the area of each affected facility. Further, impacts to existing emergency access at the affected facilities would also not be affected because PR 1179.1 does not contain any requirements specific to emergency access points and each affected facility would be expected to continue to maintain their existing emergency access. As a result, PR 1179.1 is not expected to result in inadequate emergency access.

Conclusion

Based upon these considerations, significant adverse transportation and traffic impacts are not expected from implementing PR 1179.1. Since no significant transportation and traffic impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XVIII. WILDFIRE. If located in or near state responsibility areas or lands classified as very high fire hazard severity zones, would the project:				
a) Substantially impair an adopted emergency response plan or emergency evacuation plan?	☐	☐	☐	☑
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?	☐	☐	☐	☑
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?	☐	☐	☐	☑
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?	☐	☐	☐	☑
e) Expose people or structures, either directly or indirectly, to a significant risk of loss, injury or death involving wildfires?	☐	☐	☐	☑

Significance Criteria

A project’s ability to contribute to a wildfire will be considered significant if the project is located in or near state responsibility areas or lands classified as very high fire hazard severity zones, and any of the following conditions are met:

- The project would substantially impair an adopted emergency response plan or emergency evacuation plan.
- The project may exacerbate wildfire risks by exposing the project’s occupants to pollutant concentrations from a wildfire or the uncontrolled spread of a wildfire due to slope, prevailing winds, and other factors.
- The project may exacerbate wildfire risks or may result in temporary or ongoing impacts to the environment because the installation or maintenance of associated infrastructure (such as roads, fuel breaks, emergency water sources, power lines, or other utilities) are required.
- The project would expose people or structures to significant risks such as downslope or downstream flooding or landslides, as a result of runoff, post-fire slope instability, or drainage changes.

- The project would expose people or structures, either directly or indirectly, to a significant risk of loss, injury or death involving wildfires.

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

XVIII. a), b), c), d), & e) No Impact. Of the 30 facilities subject to PR 1179.1, none are located in or near state responsibility areas or lands classified as very high fire hazard severity zones. Further, as explained in Section VIII. f), the proposed project would not impair the implementation of, or physically interfere with any adopted emergency response plans or emergency evacuation plans that may be in place at the existing facilities because PR 1179.1 does not require the new or altered use of hazardous materials and would not involve any alterations to buildings or structures. In addition, implementation of PR 1179.1 will not require the construction of any new buildings or structures. Thus, PR 1179.1 is not expected to substantially impair an adopted emergency response plan or emergency evacuation plan in effect at any of the facilities subject to PR 1179.1. In the event of a wildfire, no exacerbation of wildfire risks, and no consequential exposure of 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. Thus, PR 1179.1 would neither 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, nor would it expose people or structures, either directly or indirectly, to a new significant risk of loss, injury, or death involving wildfires. Finally, PR 1179.1 does not require new or alter existing maintenance of associated infrastructure at or surrounding affected facilities (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. Thus, PR 1179.1 is not expected to have any influence on the occurrence of wildfires or any facility’s ability to combat or prepare for wildfires.

Conclusion

Based upon these considerations, significant adverse wildfire risks are not expected from implementing PR 1179.1. Since no significant wildfire risks were identified, no mitigation measures are necessary or required

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XIX. MANDATORY FINDINGS OF SIGNIFICANCE.				
a) Does the project have the potential to degrade the quality of the environment, substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, reduce the number or restrict the range of a rare or endangered plant or animal or eliminate important examples of the major periods of California history or prehistory?	☐	☐	☐	☑
b) Does the project have impacts that are individually limited, but cumulatively considerable? (“Cumulatively considerable” means that the incremental effects of a project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects)	☐	☐	☑	☐
c) Does the project have environmental effects that will cause substantial adverse effects on human beings, either directly or indirectly?	☐	☐	☑	☐

Discussion

PR 1179.1 establishes BARCT emission limits for 82 boilers, steam generators, process heaters, turbines and engines which operate at 30 POTW facilities. Most of the affected combustion equipment are fueled by digester gas or a digester gas blend, except for large turbines rated at greater than 0.3 MW which may also be fueled by natural gas. PR 1179.1 also establishes requirements for POTWs to conduct source tests and monitoring, keep records, and prepare reports. All but one POTW facility, which operates three large turbines, currently operate their affected equipment pursuant to South Coast AQMD permits which contain the BARCT emission limits that will be memorialized in PR 1179.1. In order to reduce NOx emissions to meet BARCT (e.g., 18 ppm NOx), the remaining facility indicated that no additional air pollution control equipment will need to be installed and no replacement or retrofit of their existing turbines will be necessary. Instead, the POTW facility indicated that further NOx emission reductions can be achieved by increasing the quantity of water currently injected into combustion chamber for each of the three turbines by approximately 8,000 gallons per day per turbine for a total daily increase of 24,000 gallons. As such, the responses to the environmental checklist questions focus on the potential secondary adverse environmental impacts associated with the increased amount of water injection that is expected to occur in order to attain the desired NOx emission reductions.

XIX. a) No Impact. The 30 existing facilities that are subject to PR 1179.1 are located within existing developed areas that have been greatly disturbed and that currently do not support any species of concern or the habitat on which they rely. Further, as explained in Section IV - Biological Resources, PR 1179.1 is not expected to significantly adversely affect plant or animal species or the habitat on which they rely because the proposed project will not lead to any activities that will reduce or eliminate any plant or animal species or destroy prehistoric records of the past.

XIX. b) Less Than Significant Impact. Based on the foregoing analyses, PR 1179.1 would not result in significant adverse project-specific environmental impacts. Potential adverse impacts from implementing PR 1179.1 would not be "cumulatively considerable" as defined by CEQA Guidelines Section 15064(h)(1) for any environmental topic because there are no, or only minor incremental project-specific impacts that were concluded to be less than significant. Per CEQA Guidelines Section 15064(h)(4), the mere existence of significant cumulative impacts caused by other projects alone shall not constitute substantial evidence that the proposed project's incremental effects are cumulatively considerable. South Coast AQMD cumulative significant thresholds are the same as project-specific significance thresholds.

Therefore, there is no potential for significant adverse cumulative or cumulatively considerable impacts to be generated by PR 1179.1 for any environmental topic area.

XIX. c) Less Than Significant Impact. Based on the foregoing analyses, PR 1179.1 is not expected to cause adverse effects on human beings for any environmental topic, either directly or indirectly because: 1) the reduction of NOx emissions is an air quality benefit and no adverse air quality or GHG impacts were identified in Section III – Air Quality and Greenhouse Gases; 2) energy impacts were determined to be less than significant as analyzed in Section VI – Energy; and 3) the increased water usage and wastewater was determined to be less than significant as analyzed in Section IX – Hydrology and Water Quality.; . In addition, the analysis concluded that there would be no significant environmental impacts for the remaining environmental impact topic areas: aesthetics, agriculture and forestry resources, biological resources, cultural and tribal cultural resources, geology and soils, hazards and hazardous materials land use and planning, mineral resources, noise, population and housing, public services, recreation, solid and hazardous waste, transportation, and wildfire.

Conclusion

As previously discussed in environmental topics I through XIX, the proposed project has no potential to cause significant adverse environmental effects. Since no significant impacts were identified, no mitigation measures are necessary or required.

APPENDICES

Appendix A:	**Proposed Rule 1179.1 – ~~NOx~~ Emissions Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities**
Appendix B:	**Operational Emissions Assumptions and Calculations**
Appendix C:	**PR 1179.1 List of Affected Facilities and Affected Industry**
Appendix D:	**Comment Letter Received on the Draft EA and Response**

APPENDIX A

Proposed Rule 1179.1 – ~~NOx~~ Emissions Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities

In order to save space and avoid repetition, please refer to the latest version of PR 1179.1 located elsewhere in the Governing Board Package (meeting date October 2, 2020). The version of PR 1179.1 that was circulated with the Draft EA and released on August 12, 2020 for a 30-day public review and comment period ending on September 11, 2020 was identified as Proposed Rule 1179.1 - Preliminary Draft Rule Language (July 22, 2020) which is available from the South Coast AQMD's website at: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1179.1/pr-1179-1---final.pdf. Original hard copies of the Draft EA, which include the draft version of the proposed rule listed above, can be obtained by contacting the Public Information Center by phone at (909) 396-2001 or by email at PICrequests@aqmd.gov.

APPENDIX B

Operational Emissions Assumptions and Calculations

Appendix B: Operational Emissions Assumptions and Calculations

Mobile Source Emissions for Operation

Activity	Trip Distance (miles)	CO2 Emissions (lb/mile)	Number Trips/yr	CO2 Emissions (lb/yr)	CO2 Emissions (MT/yr)
Source Test Trips - Passenger Auto	40	1.93	2.00	154.40	0.07
Source Test Trips - Medium Duty Truck	40	0.79	2.00	63.20	0.03
Total				217.60	0.10

CO2 emission factors obtained from EMFAC 2017

Onroad Vehicles, VMT + Fuel Usage

	Activity	Description	Trip Distance (miles)	Number Trips/yr	VMT	Fuel Type	MPG	Gallons Fuel	Peak Day Trips
Phase	Source Test Trips - Passenger Auto	10 Source Tests (5 per facility)	40	2.0	80.0	Gasoline	21	4	2
	Source Test Trips - Medium Duty Truck	10 Source Tests (5 per facility)	40	2.0	80.0	Diesel	10	8	2
	Total VMT				160				4

VMT = vehicle miles traveled
MPG = miles per gallon
Fuel Usage = VMT / MPG

EMFAC 2017 Emission Factors (lbs/mile)

Vehicle Type	-	VOC	NOx	CO	SOx	PM10	PM2.5	CO2	CH4
Light Duty Auto	-	0.000440	0.004682	0.002427	0.000019	0.000388	0.000244	1.927986	0.000042
Medium Duty/ Delivery	-	0.000392	0.000299	0.003638	0.000008	0.000104	0.000044	0.789383	0.000041

Mobile Emissions (lbs/trip)

Trip Type	Miles	VOC	NOx	CO	SOx	PM10	PM2.5	CO2	CH4	CO2e
One Light Duty Auto Worker Trip - Source Testing	40	0.018	0.187	0.097	0.001	0.016	0.010	77.119	0.002	77.161
One Medium Duty Source Testing Trip	40	0.016	0.012	0.146	0.000	0.004	0.002	31.575	0.002	31.617

Calculations
Mobile Emissions = Emission Factor * Miles
CO2e = CO2 + 25*CH4

APPENDIX C

PR 1179.1 List of Affected Facilities and Affected Industry

Appendix C: PR 1179.1 List of Affected Facilities and Affected Industry

Facility ID	Facility Name	Facility Address	On List per Government Code 65962.5	Distance from School (meters)	Distance from Sensitive Receptor (meters)	Located Within Two Miles of an Airport?
1179	Inland Empire Utilities Agency Water Reclamation Facility Regional Plant #2	16400 El Prado Rd, Chino 91710	No	1370	694	Yes
1703	Eastern Municipal Water District	42565 Avenida Alvarado, Temecula 92590	No	2090	928	No
2537	Corona City, Department of Water & Power	2205 Railroad St, Corona 92880	No	1870	1190	Yes
3513	Irvine Ranch Water District	3512 Michelson Dr., Irvine 92612	No	1530	649	Yes
3866	South Orange County Wastewater Authority	34156 Del Obispo St., Dana Point 92629	No	410	45	No
5756	Redlands Wastewater Treatment Plant	1950 Nevada St., Redlands 92373	No	1450	1800	Yes
7417	Eastern Municipal Water District	1301 Case Rd., Perris 92570	No	1770	896	Yes
9163	Inland Empire Utilities Agency	2662 E. Walnut St., Ontario 91761	Yes	419	5	Yes
9961	Riverside Water Quality Control Plant	5950 Acorn St., Riverside 92504	No	812	589	Yes
10198	Valley Sanitary District	45-500 Van Buren St., Indio 92201	No	882	587	No
10245	Terminal Island Water Reclamation Plant	445 Ferry St., San Pedro 90731	Yes	2010	1260	No
11301	San Bernardino Water Reclamation Facility	399 Chandler Pl., San Bernardino 92408	No	1620	344	Yes
12923	Rialto City	501 E Santa Ana Ave., Bloomington 92316	No	2690	1740	No
13088	Eastern Municipal Water District	17140 Kitching St., Moreno Valley 92551	No	686	72	Yes
13433	South Orange County Wastewater Authority-Regional Treatment Plant	29200-01 La Paz Rd., Laguna Niguel 92677	No	622	255	No
17301	Orange County Sanitation District	10844 Ellis Ave., Fountain Valley 92708	No	413	234	No
19159	Eastern Municipal Water District	770 N Sanderson Ave., San Jacinto 92582	No	1090	648	No
20237	San Clemente City, Wastewater Division	380 Avenida Pico, San Clemente 92672	No	593	53	No
20252	Banning City Waste Water Treatment Plant	2242 E Charles St., Banning 92220	No	2180	378	Yes
22674	Los Angeles County Sanitation District Valencia Plant	28185 The Old Rd., Valencia 91355	No	2650	1430	No
29110	Orange County Sanitation District	22212 Brookhurst St., Huntington Beach 92646	No	598	38	No
50402	Yucaipa Valley Water District	880 W County Line Rd., Yucaipa 92399	No	2230	698	No
51304	Santa Margarita Water District	26111 Antonio Pkwy., Rancho Santa Margarita, 92688	No	800	800	No
94009	Las Virgenes	3700 Las Virgenes Rd., Calabasas 91302	No	730	185	No
111176	Western Riverside County Regional Wastewater Authority	14634 River Rd., Corona 92880	No	747	37	Yes
118526	Western Municipal Water District	22751 Nandina Ave., Riverside 92518	No	2550	1020	Yes
147371	Inland Empire Utilities Agency	6063 Kimball Ave., Chino 91710	No	1020	410	Yes
181040	Santa Margarita Water District - 3A Treatment Plant	26801 Camino Capistrano, Laguna Niguel, 92677	No	2800	370	No
800214	Hyperion Water Reclamation Plant	12000 Vista Del Mar, Playa Del Rey 90293	No	668	100	Yes
800236	Los Angeles County Joint Water Pollution Control Plant	24501 S. Figueroa St., Carson 90745	No	822	232	No

NAICS Code	Description of Industry
221320	Sewage Treatment Facilities

APPENDIX D

Comment Letter Received on the Draft EA and Response

Comment Letter #1

STATE OF CALIFORNIA—CALIFORNIA STATE TRANSPORTATION AGENCY Gavin Newsom, Governor

DEPARTMENT OF TRANSPORTATION
DISTRICT 7 – Office of Regional Planning
100 S. MAIN STREET, MS 16
LOS ANGELES, CA 90012
PHONE (213) 897-9140
FAX (213) 897-1337
TTY 711
www.dot.ca.gov

Making Conservation a California Way of Life.

September 8, 2020

Barbara Radlein
South Coast Air Quality Managing District
21865 Copley Drive
Diamond Bar, CA 91765-4182

RE: Proposed Rule 1179.1 – Environmental Assessment (EA)
SCH # 2020080171
GTS # 07-MULTIPLE-2020-00167
Vic. South Coast Air Quality Management District

Dear Barbara Radlein:

Thank you for including the California Department of Transportation (Caltrans) in the environmental review process for this project's Environmental Assessment (EA). Proposed Rule (PR) 1179.1 proposes to establish Best Available Retrofit Control Technology (BARCT) requirements for combustion equipment operated at Publicly Owned Treatment Works (POTW) facilities to reduce emissions of: 1) NOx and CO from boilers, steam generators and process heaters rated greater than 400,000 British thermal units (Btu) per hour fueled by digester gas or a digester gas blend; 2) NOx and CO from turbines rated less than 0.3 megawatt (MW) fueled by digester gas or a digester gas blend; 3) NOx and CO from turbines rated at greater than or equal to 0.3 MW fueled by natural gas, digester gas, or a digester gas blend; and 4) NOx, CO and VOC from engines rated at greater than 50 rated brake horsepower (bhp) fueled by digester gas or a digester gas blend.

After reviewing the EA, Caltrans does not expect project approval to result in a direct adverse impact to the existing State transportation facilities.

For future site specific CEQA evaluations, please keep in mind any work performed within Caltrans' Right-of-Way (R/W) will require further review and approval by Caltrans. Any proposed work within Caltrans' R/W will require an encroachment permit prior to activities or construction.

If you have any questions, please contact Reece Allen, the project coordinator, at reece.allen@dot.ca.gov, and refer to GTS # 07-MULTIPLE-2020-00167

Sincerely,

MIYA EDMONSON
IGR/CEQA Branch Chief
cc: Scott Morgan, State Clearinghouse

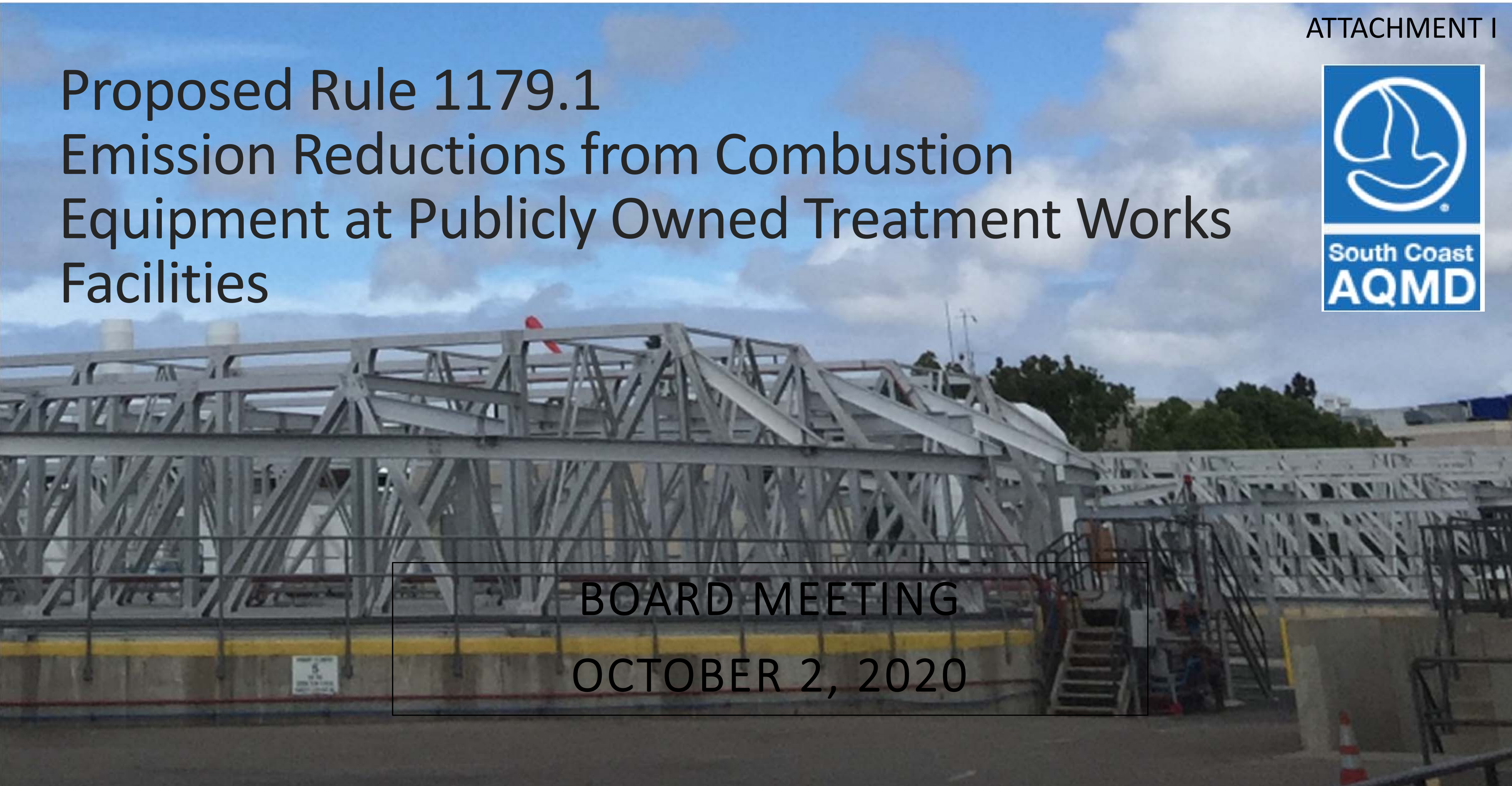
"Provide a safe, sustainable, integrated and efficient transportation system to enhance California's economy and livability"

Response to Comment Letter #1

This comment letter summarizes the key elements of PR 1179.1 and concludes that implementation of the proposed project will not likely result in a direct adverse impact to existing State transportation facilities, indicating agreement with the conclusion in the Final EA that no significant transportation impacts were identified. This comment letter also indicates that for future site-specific CEQA evaluations which involve any work performed within Caltrans' Right-of-Way will require further review and approval by Caltrans, including an encroachment permit prior to activities or construction. Since implementation of PR 1179.1 will not involve any future site-specific construction or other activities involving roadways within Caltrans' Right-of-Way, no review and approval of an encroachment permit will be required.

ATTACHMENT I

Proposed Rule 1179.1
Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities



South Coast AQMD

BOARD MEETING

OCTOBER 2, 2020

Background

- Proposed Rule 1179.1 (PR 1179.1) was developed to regulate combustion equipment at publicly owned treatment works (POTWs)
  - POTWs are essential public services
  - Digester gas has contaminants that require gas clean up
  - POTWs are publicly funded
- Most combustion equipment at POTWs are currently regulated under existing rules
- A comprehensive BARCT assessment on combustion equipment was performed to assess if NOx limits could be further reduced

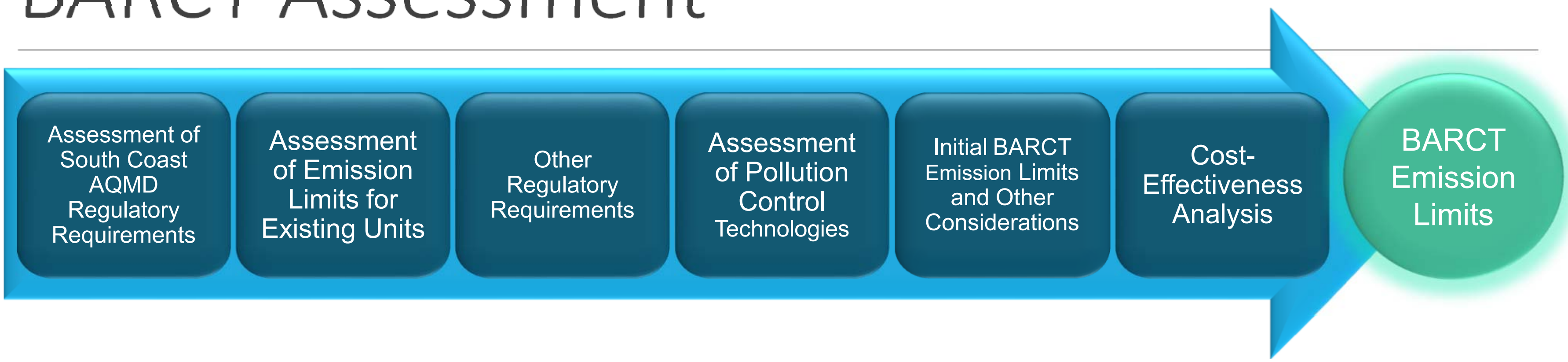
Applicability of PR 1179.1

- PR 1179.1 will apply to 30 POTW facilities
- PR 1179.1 applies to digester gas-fired boilers, turbines and engines
  - Addresses NOx, CO and VOC
- Also applies to natural gas-fired turbines at POTWs

Proposed Amendments

- Most provisions reflect existing requirements from source-specific rules for boilers, engines and turbines
- PR 1179.1 contains requirements for:
  - Emission limits
  - Averaging times
  - Startup and shutdown
  - Source testing
  - Monitoring, reporting and recordkeeping

BARCT Assessment



- BARCT emission limits represent the maximum degree of reductions achievable, taking into account environment, energy, and economic impacts for this class/category of sources
- Conducted a BARCT assessment for boilers and turbines that are fueled with digester gas
  - Only lower NOx limits for turbines were found to be cost-effective
- Staff relied on the 2019 BARCT assessment for engines

Proposed NOx Emission Limits

- Turbines ≥ 0.3 MW would be subject to an 18.8 ppm NOx emission limit
  - Affects 3 turbines at one facility
- NOx emission limits for other equipment reflect current rule/permit requirements

Equipment Category	NOx Emission Limit*
Boilers > 2 MMBtu/hr	15 ppm
Boilers ≤ 2 MMBtu/hr	30 ppm
Turbines ≥ 0.3 MW	18.8 ppm (new limit)
Turbines < 0.3 MW	9 ppm
Engines	11 ppm

*Emission limits corrected to 3% O2 for boilers and 15% O2 for turbines and engines

Other Proposed Amendments

Startup and Shutdown

- New startup and shutdown provisions for turbines

Monitoring, Reporting, and Recordkeeping

- Added requirement to keep records for service, tuning and hours of operation
- Added requirement that all records be kept for 5 years

Cost-Effectiveness and Emission Reductions

Cost-effectiveness

- Cost-effectiveness for the rule is approximately $50,000 per ton of NOx reduced*

Emission Reductions

- Emission reductions from turbines subject to PR 1179.1 are 0.05 tons per day of NOx

*Cost-effectiveness for turbines to meet the proposed emission limit only is $48,600 per ton of NOx reduced

Staff Recommendation

- Staff is not aware of any key remaining issues
- Recommendation is to adopt Resolution:
  - Certifying the Final Environmental Assessment for PR 1179.1
  - Adopting Rule 1179.1