SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Draft Staff Report

Proposed Amendments to Regulation XX
Regional Clean Air Incentives Market (RECLAIM)
NOx RECLAIM

October 6, 2015

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

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

Planning & Rules Director
Planning, Rule Development, and Area Sources
Joe Cassmassi

Authors
Minh Pham, P.E. – Air Quality Specialist
Kevin Orellana – Air Quality Specialist

Reviewed By
Gary Quinn, P.E. – Program Supervisor
Danny Luong, P.E. – Senior Enforcement Manager
William Wong – Principal Deputy District Counsel
Barbara Baird - Chief Deputy Counsel

Acknowledgement

The authors would like to thank the following staff members for providing information for and participating in this project:

Planning, Rule Development & Area Sources
Elaine Chang (retired), Shah Dabirian, Elaine Shen, Priscilla Hamilton, Ian MacMillan, Barbara Radlein, James Koizumi, Ali Ghasemi, Susan Yan, Wayne Barcikowski

Engineering & Compliance
Mohsen Nazemi, Danny Luong, Mitch Haimov, Bob Sanford, Fortune Chen, Susan Tsai, Kyu Kyu Remillard, Tran Vo, Paul Park, Connie Yee, Janice West, Khang Nguyen, Sawsan Andrawis, Rafik Beshai, Andrew Lee, John Yee and their team

Science & Technology Advancement
Laki Tisopulos, Mike Garibay, Dipankar Sarkar, Peter Ko, Tom Lee, Glenn Kasai, Scott Wilson and their team

Information Management
Chris Marlia, Ora McEwan, Xin Chen, Rezvan Ramezani, George Haddad

Table of Contents

List of Tables

List of Figures

List of Acronyms

AC	Annual Operating Cost
AER	Annual Emissions Report
AQMP	Air Quality Management Plan
ASC	Ammonia Slip Catalyst
Basin	South Coast Air Basin
BACT	Best Available Control Technology
BARCT	Best Available Retrofit Control Technology
CARB	California Air Resources Board
CE	Cost Effectiveness
CEMS	Continuous Emissions Monitoring System
CLN™	Cheng Low NOx Control Technology
CM	Control Measure
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CR	Catalyst Replacement
CY	Compliance Year
DCF	Discounted Cash Flow Method
DLN/DLE	Dry Low NOx/Dry Low Emissions
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
ER	Emission Reductions
ESP	Electrostatic Precipitator
ETS	Environmental Technology Services
^{o} F	Degree Fahrenheit
FCCU	Fluid Catalytic Cracking Unit
HHV	High Heating Value of Fuel
HRSG	Heat Recovery Steam Generator
H&SC	Health & Safety Codes
GF	Growth Factor
LCF	Levelized Cash Flow Method
LoTOx™	Low Temperature Oxidation Process for NOx Control
NAAQS	National Ambient Air Quality Standards
NEC	Norton Engineering Consultants
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
N_2O	Nitrous Oxide
NOx	Nitrogen Oxides
OCS	Outer Continental Shelf
OAQPS	Office of Air Quality Planning and Standards
PAR	Proposed Amended Rule or Proposed Amended Regulation
ppm	Parts Per Million
PWV	Present Worth Values
RACM	Reasonably Achievable Control Measure
RACT	Reasonably Achievable Control Technology
RECLAIM	Regional Clean Air Incentive Market Program
RTC	RECLAIM Trading Credit

SCAQMD	South Coast Air Quality Management District
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non Catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SOx	Sulfur Oxides
SRU/TG	Refinery's Sulfur Recovery Unit /Tail Gas Treating Unit
TIC	Total Installed Costs
tpd or TPD	Tons Per Day
Ultra-Cat™	Ultra-Cat Catalyst Filter Manufactured by Tri-Mer Corporation
WHB	Waste Heat Boiler
WGM	Working Group Meeting
WSPA	Western States Petroleum Association

Executive Summary

Background

On October 15, 1993, the South Coast Air Quality Management District (SCAQMD) Governing Board adopted Regulation XX - REgional Clean Air Incentives Market (RECLAIM). Regulation XX includes rules that specify the applicability and procedures for determining NOx and SOx facility emissions allocations, program requirements, as well as monitoring, reporting, and recordkeeping requirements for sources located at RECLAIM facilities. RECLAIM was designed to provide equivalent emission reduction in the aggregate for the facilities in the program compared to what would occur under a command-and-control approach, with flexibility for each facility to find the most cost-effective strategy to meet their emission reduction targets. The program requires robust monitoring to ensure compliance. Over the past more than 20 years, the program has resulted in significant emission reductions. The RECLAIM program started with 392 NOx facilities in 1993. By the end of compliance year 2013, there were 275 facilities in the NOx RECLAIM universe.

Best Available Retrofit Control Technology for RECLAIM

When the NOx RECLAIM program was first adopted, the NOx RECLAIM facilities were issued NOx annual allocations (also known as facility caps), which declined annually from 1993 until 2003 and remained constant after 2003. The annual allocations issued to the NOx RECLAIM facilities reflected the levels of Best Available Retrofit Control Technology (BARCT) envisioned to be in place at the RECLAIM facilities, and were the result of a BARCT analysis conducted in 1993. A BARCT reassessment is required by the California Health & Safety Code (H&SC) §40440 to assess the advancement in control technology and to ensure that RECLAIM facilities achieve the same emission reductions that would have occurred under a command-and-control approach and that emission reductions from the program contribute to the efforts in the Basin to achieve the federal National Ambient Air Quality Standards (NAAQS). The SCAQMD staff conducted a BARCT reassessment for NOx in 2005 and another for SOx in 2010, and subsequently amended the RECLAIM rules to reduce the facility annual allocations. RECLAIM facilities have the flexibility to install air pollution control equipment, change their operations, or purchase RECLAIM Trading Credits (RTCs).

Ozone Non-Attainment Status

On March 12, 2008, the EPA strengthened its ground-level 8-hour ozone standard from 0.08 parts per million (ppm) to 0.075 ppm. On May 21, 2012, the EPA classified two areas in the country, the South Coast and the San Joaquin Valley, as "Extreme" non-attainment areas with respect to the 2008 8-hour ozone standard. The attainment dates for the 1997 and 2008 ozone standards are

June 15, 2024 and July 20, 2032, respectively with emissions reductions and attainment required in the previous calendar year. NOx is a precursor for ozone. Significant reductions in NOx emissions are necessary for the Basin to attain the 24-hour PM2.5 standard in 2019 and the ozone ambient air quality standards in 2023 and 2031.

2012 Air Quality Management Plan and Control Measure CMB-01

The SCAQMD developed and adopted the 2012 Air Quality Management Plan (AQMP) in partnership with CARB, U.S. EPA, SCAG and stakeholders throughout the region to outline the strategy to meet and maintain the state and federal air quality standards. The 2012 AQMP identified control measures needed to attain the federal 24-hour standard for PM2.5 by 2014 and provided updates on progress towards meeting the 8-hour ozone standard in 2023. Control Measure CMB-01 – Further NOx Reduction for RECLAIM is one of the control measures included in the 2012 AQMP. Control Measure CMB-01 called for a reassessment of BARCT for NOx RECLAIM facilities and estimated that a total of 2-3 tons per day (tpd) of NOx emission reductions could be achieved in 2014 for Phase I with an additional of 1-2 tpd NOx in 2020 for Phase II following the BARCT analysis. CMB-01 Phase I served as a PM2.5 SIP contingency measure for the 2012 AQMP, and if emission reductions were not needed in Phase I, the RTC reductions estimated for Phase I would be combined with the total reductions that could be achieved in Phase II. It was anticipated that NOx emissions reductions from both phases would also contribute to meeting the ozone standards in 2024 and 2032.

Current Emissions and RTC Holdings

The 2011 audited actual emissions were 20 tons per day (tpd) for the RECLAIM universe (59% from the refineries and 41% from the non-refinery sector). For electrical generating facilities, staff used 2012 emissions instead of 2011 due to several reasons: 1) local electrical generating facilities in the region operated more in 2012 to make up for the closure of the San Onofre Nuclear Generation Station (SONGS), 2) the commissioning of new electrical generating facilities in the region was reflected more accurately in 2012, and 3) a recent shift in the use of renewable energy sources, such as wind, solar, and water, and their inherent intermittency resulted in the use of peaking units with increased numbers of startups and associated emissions. The 2011/2012 baseline emissions for the NOx RECLAIM universe in this analysis were 20.7 tpd.

The RECLAIM Trading Credit (RTC) holdings for the RECLAIM universe were 26.5 tpd, of which the refinery sector held 51% of the RTCs, electrical generating facilities 21%, investors 4% and other RECLAIM facilities 24%.

Proposed BARCT, Emission Reductions, and RTC Reductions

The BARCT analysis resulted in the BARCT levels and incremental emission reductions by 2023 shown in Table EX.1. For the refinery sector, a new level of BARCT is proposed for fluid catalytic cracking units, boilers/heaters >40 mmbtu/hr, gas turbines, coke calciners, and sulfur recovery and tail gas incinerators. For the non-refinery sector, a new BARCT level is proposed for container glass melting furnaces, cement kilns, sodium silicate furnaces, metal melting furnaces >150 mmbtu/hr, gas turbines and ICEs not located on the outer continental shelf (OCS). No new BARCT is proposed for electrical generating facilities.[1]

Table EX. 1 - Summary of Proposed BARCT (May 2015)

Refinery Sector	2015 BARCT Level	Incremental Emission Reductions from 2000/2005 BARCT (tpd)
Fluid Catalytic Cracking Units	2 ppmv at 3% O2	0.43
Refinery Boilers and Heaters >40 mmbtu/hr	2 ppmv or 0.002 lb/mmbtu	0.94
Refinery Gas Turbines	2 ppm at 15% O2	4.14
Coke Calciner	10 ppmv at 3% O2	0.17
Sulfur Recovery Units Tail Gas Incinerators	2 ppmv at 3% O2 or 95% reduction	0.32
	Total	**6.00**

Non-refinery Sector	2015 BARCT Level	Incremental Emission Reductions from 2000/2005 BARCT (tpd)
Container Glass Melting Furnaces	80% reduction	0.24
Sodium Silicate Furnace	80% reduction	0.09
Metal Heat Treating Furnaces >150 mmbtu/hr	9 ppmv at 3% O2	0.56
Gas Turbines (non-OCS)	2 ppmv at 15% O2	1.04
Internal Combustion Engines (non-OCS)	11 ppmv at 15% O2	0.84
Cement Kilns	0.5 lbs/ton	1.29 (note)
	Total	**2.77**

Note: The 1.29 tpd emission reductions from cement kilns were not included in the 2.77 tpd emission reductions because the cement facility was not in operation in 2011. Cement kilns were the highest emitting stationary source of NOx emissions in 2008, thus staff conducted a BARCT analysis for cement kilns and reduced the remaining emissions projected to the 2023 level for the cement facility to the BARCT level.

[1] Staff conducted a BARCT analysis focusing on the top 37 NOx emitting facilities in 2011, and a cement plant which was the highest NOx emitting stationary source in 2008. The BARCT analyses with detailed information are in the appendices (Appendices A-J of Part I for the refinery sector, and Appendices M-S of Part II for the non-refinery sector.)

As shown in Table EX.1, the total BARCT-equivalent emission reductions are 8.8 tpd (6.00 tpd for the refinery sector and 2.77 tpd for the non-refinery sector.) Due to projected growth,[2] the remaining emissions in 2023 at these proposed 2015 BARCT levels would be 10.2 tpd (2.76 tpd for the refinery sector and 7.47 tpd for the non-refinery sector.) Staff has added a 10% compliance margin to the 2023 remaining emissions. In addition, staff has added the remaining emissions from shutdown glass and cement facilities at BARCT levels, thereby adding to the compliance margin, as well as the emissions for new facilities entering RECLAIM program since 2005 to the total remaining emissions. Staff has provided some adjustments to account for uncertainties that arose in the BARCT analysis and for additional 2011 activity level adjustment. This results in total proposed NOx RTC reductions of 14 tpd from the current RTC holdings of 26.5 tpd in 2023.[3] The remaining RTCs for the NOx RECLAIM universe would be 12.5 tpd (26.5 tpd – 14 tpd = 12.5 tpd), which is 2.3 tpd or almost 23% above the projected remaining emissions from RECLAIM NOx sources in 2023. See Figure EX.1.

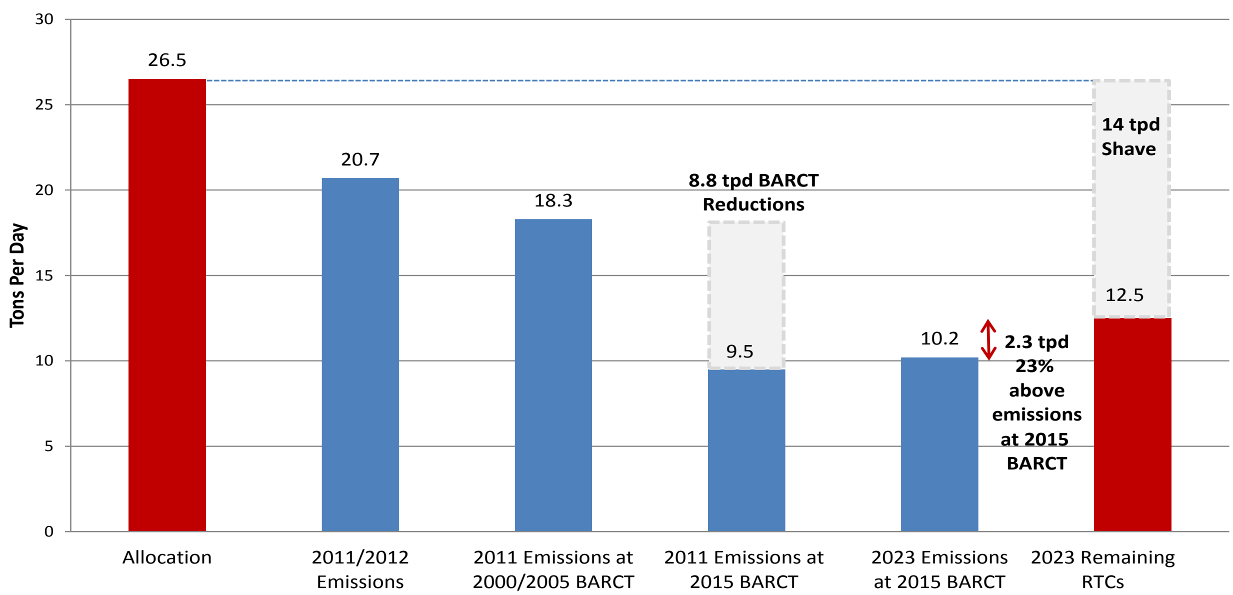


Figure EX. 1 – Audited Emissions and RTC Holdings

Staff is proposing to distribute the 14 tpd NOx RTC reductions to 56 facilities and investors that hold 90% of the 26.5 tpd RTCs. Investors are grouped with the refineries and treated as a facility for shave purposes. The remaining 219 facilities that hold 10% of the 26.5 tpd RTC are not proposed to be shaved because there was limited or no new BARCT for the types of equipment

[2] The growth factor for the refineries is 1. Electric generating facilities are expected to be more efficient with growth factor of 0.89 (2014 California Gas Report). The average growth factor for other non-refinery facilities is 1.1 (Southern California Association of Government (SCAG)).

[3] RTC Reductions = RTC Holdings – Remaining Emissions in 2023 - Adjustments = 14 tpd. Refer to Chapter 5 and Appendix U of Part III for detailed information.

and operation at these facilities.[4] Staff's current proposal is to weight the amount of shave considering the technology available to different facility types as summarized below:

66% shave for 9 refineries and investors
49% shave for 21 electrical generating facilities
49% shave for 26 other major facilities
0% shave for 219 remaining facilities

The 2023 remaining emissions after installing BARCT, the RTC holdings after the shave, and the surplus or deficit RTCs after the shave for each industry sector are presented in Table EX.2. After the shave, the 9 refineries, the investors, and the 21 electrical generating facilities would have surplus RTCs. Some facilities in the 26 non-electrical generating facilities and the 219 remaining facilities would not be subject to any shave however their emissions would grow above the RTC holdings that they currently have and they would have to purchase RTCs from other industry sectors to reconcile their projected emissions. Overall, there is a net of 2.3 tpd surplus RTCs for the entire RECLAIM universe.

Table EX. 2 – Summary of 2023 RTC Holdings and 2023 Emissions After BARCT

	9 Refineries	**15 Investors**	**21 Electrical generating facilities**	**26 Non-Electrical generating facilities**	**219 Other Facilities**	**Net Total**
Current RTC Holdings (tpd) (note)	14.15	0.42	5.63	3.45	2.86	26.5
% Shave	66%	66%	49%	49%	0%	
RTC Holdings After Shave (tpd)	4.81	0.14	2.87	1.76	2.86	12.5
2023 Emissions After BARCT (tpd)	2.76	0	2.04	1.93	3.5	10.2
Surplus or Deficit RTCs (tpd)	2.05	0.14	0.83	(0.17)	(0.64)	2.3

Note: RTC Holdings as of September 22, 2015

Staff is proposing to implement the 14 tpd RTC reductions over a 7-year period from 2016 to 2022 but as expeditiously as possible to help the Basin meet the PM2.5 standard deadlines as well as the ozone standards in 2023 and 2031. Staff is proposing the following implementation schedule for NOx RTC reductions:

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

[4] The ICEs and small boilers or heaters in the remaining 219 facilities could be subject to additional BARCT but the potential emission reductions totaled less than 0.1 tpd.

2022 – 2 tons per day

Over the past five years from 2009-2013, the unused RTCs in the NOx RECLAIM program ranged from 5 tpd to 8 tpd. Staff is proposing a 4 tpd RTC reduction in 2016. Additional BARCT implementation will take about 2 - 4 years for planning, permitting, and construction, and thus staff is proposing the remaining shave of 10 tpd to take place over five years from 2018 to 2022.

The BARCT analyses are described in Chapter 3, the costs and cost effectiveness of the proposal are described in Chapter 4 and are summarized in Table EX.3. The total Present Worth Values (PWVs) of the project range from $728 M to $1.1 B, and the overall cost effectiveness values of the project as a whole range from $9 K to $14 K per ton NOx reduced. Individual category cost-effectiveness is set forth in the table below. The RTC reductions are estimated in Chapter 5, and the proposed changes in rule language are described in Chapter 6.

Table EX. 3 - Summary of Costs and Cost Effectiveness

	2015 BARCT	Incremental Emission Reductions from 2000/2005 BARCT (tpd)	Number of Affected Facilities	Estimated No of Control Devices	PWVs ($M)	Incremental Cost Effectiveness (thousand dollars/ton)
Refinery Sector						
FCCUs	2 ppmv	0.43	5	5 SCRs (or 2 SCRs + 3 LoTOx/WGS)	152 - 391	3 - 13
Boilers and Heaters	2 ppmv	0.94	8	75 SCRs	237	28
Refinery Gas Turbines	2 ppm	4.14	5	7 SCRs and adding catalysts to 4 SCRs	53 - 98	1 - 3
Coke Calciner	10 ppmv	0.17	1	1 UltraCat (or 1 LoTOx/WGS)	40 - 91	22 - 35
SRU/TG Incinerators	2 ppmv	0.32	4	6 SCRs (or 1 SCRs + 5 LoTOx/WGS)	83 - 106	28 - 40
Refinery Total		**6.00**		**92 SCRs + 1 UltraCat (or 84 SCRs and 9 LoTOx/WGS) and adding catalysts to SCRs**	**565 - 923**	**10 - 17**
Non-Refinery Sector						
Glass Melting Furnaces	80% red	0.24	1	2 SCRs (or 1 UltraCat)	6 - 15	3 - 7
Sodium Silicate Furnace	80% red	0.09	1	1 SCR (or 1 UltraCat)	3 - 5	4 - 8
Metal Heat Treating	9 ppmv	0.56	1	1 SCR	8 - 10	3 - 4
Gas Turbines (non-OCS)	2 ppmv	1.04	3	14 SCRs	~109	5 - 36
ICEs (non-OCS)	11 ppmv	0.84	7	16 SCRs	~37	5 - 8
Non-Refinery Total (w/o Cement Kilns)		**2.77**		**34 SCRs (or 31 SCRs and 2 UltraCat)**	**163 - 176**	**6 - 7**
Overall		**8.8**		**127 SCRs + 1 UltraCat (or 115 SCRs + 9 LoTOx/WGS)**	**728 - 1099**	**9 - 14**

Public Process

The public process for PAR XX – NOx RECLAIM is summarized in Table EX.4. Staff began this rulemaking process in the 4th quarter 2012. In 2013, staff formed a RECLAIM Working Group to discuss potential amendments to the NOx RECLAIM program that included members representing NOx RECLAIM facilities, the Western States Petroleum Association (WSPA), the environmental community, as well as CARB and U.S. EPA. The first meeting was conducted on January 31, 2013. A list of participants is shown in Table EX.5.

To gather pertinent information for rule development, staff sent out Survey Questionnaires to 38 facilities, including the top 37 emitting facilities in 2011 and a cement facility which was the highest NOx stationary emission sources in 2008. Since January 2013, eleven Working Group Meetings were held to discuss potential BARCT levels for major NOx sources at the top 37 and cement facilities, the emissions inventory, potential for emission reductions, and proposals for RTC reductions. [5] In addition, in September 2014, SCAQMD staff contracted with two consultants (Environmental Technology Services, Inc. (ETS) and Norton Engineering Consultants Inc. (NEC)) to conduct independent BARCT analyses. The consultants and staff visited a glass manufacturing facility, a cement manufacturing facility, and six refineries to assess the availability of space for the installation of additional controls and to discuss BARCT issues and concerns with the stakeholders. The consultants completed their analyses in December 2014, and staff held the 8th Working Group Meeting in January 7, 2015 to report on the consultants' findings to the stakeholders. A CEQA and Socioeconomic scoping session was held in January 8, 2015 and staff received ten comment letters. From January to March 2015, staff reviewed the consultants' analyses and addressed comments received in response to the CEQA and Socioeconomic scoping session. Staff also extended the contract for NEC to allow time to produce the confidential proprietary information reports for each refinery, and this task was completed in April 2015.

In addition to the twelve Working Group Meetings, staff participated in over 30 meetings with various stakeholders individually or in groups to discuss the BARCT analysis and the proposed allocation reduction distribution (shave) methodology. Staff also met with a number of air pollution control manufacturers to discuss control technologies, and invited the manufacturers to write manuscripts and give presentations at the 2014 Air & Waste Management Association annual conference in Long Beach. Several refinery representatives participated in the discussions at the conference.

---

[5] The Survey Questionnaires for the refineries and non-refineries are in Appendix L and Appendix T, respectively. The detailed BARCT analyses are in the relevant appendices (Appendices A-J for refinery sector and Appendices M-S for non-refinery sector.) Staff focused on the top 37 emitting facilities contributing more than 85% of the 2011 emissions and the cement plant which was the highest NOx stationary emission source in 2008. Staff looked at other sources in the remaining facilities: the emission reductions from ICEs and small boilers and heaters at these facilities would generate less than 0.1 tpd emission reductions and staff did not identify any more stringent BARCT for other equipment at these facilities.

A Public Workshop was conducted on July 22, 2015, a Public Consultation Meeting was conducted on September 29, 2015, the draft Program Environmental Assessment was released on August 13, 2015 for 75 days public comments, and the draft socioeconomic analysis was released on September 9, 2015. Three Stationary Source Committee meetings were held on March 21, 2014, July 24, 2014, and October 14, 2015 including a special session requested by industry devoted to RECLAIM discussion. The Public Hearing is scheduled for November 6, 2015.

Table EX. 4 - Summary of Public Process

Calendar Year 2013	
January 31, 2013	RECLAIM Working Group was formed. The 1st RECLAIM Working Group Meeting was conducted
March 20, 2013	2nd RECLAIM Working Group Meeting
June 13, 2013	3rd RECLAIM Working Group Meeting. Staff conducted a Survey to gather information for rule development.
September 19, 2013	4th RECLAIM Working Group Meeting
Calendar Year 2014	
January 22, 2014	5th RECLAIM Working Group Meeting
March 18, 2014	6th RECLAIM Working Group Meeting
March 21, 2014	1st Stationary Source Committee Meeting
July 31, 2014	7th RECLAIM Working Group Meeting
September 2014 – December 2014	Staff contracted ETS and NEC to conduct independent BARCT analyses for the non-refinery and refinery sectors. The consultants and staff visited facilities to discuss BARCT issues with the stakeholders and assess space availability. The consultants finalized their analyses and reports in December 2014.
Calendar Year 2015	
January 7, 2015	8th RECLAIM Working Group Meeting. Staff presented the results of the consultants' analyses to the Working Group Meeting.
January 8, 2015	A CEQA and Socioeconomic Scoping session was held. Ten (10) comment letters were received.
January – March	Staff conducted a review of the consultants' analyses and addressed the comments received in the CEQA and Socioeconomic Scoping sessions.
April 10, 2015	The contract for NEC was extended to separate confidential reports for the refineries. This task was completed April 10, 2015
April 29, 2015	9th RECLAIM Working Group Meeting
June 4, 2015	10th RECLAIM Working Group Meeting
July 9, 2015	11th RECLAIM Working Group Meeting

July 22, 2015	Public Workshop. Release Preliminary Draft Staff Report and Rule Language
July 24, 2015	2nd Stationary Source Committee Meeting
August 13, 2015	Release Draft Program Environmental Assessment. Draft PEA commenting period extended to October 6, 2015
September 9, 2015	Release Draft Socioeconomic Report
September 23, 2015	3rd Stationary Source Committee Meeting 12th RECLAIM Working Group Meeting
September 29, 2015	Public Consultation Meeting
October 14, 2015	3rd Stationary Source Committee Meeting
November 6, 2015	Public Hearing

Table EX. 5 - List of Participants

Organizations
California Council for Environmental and Economic Balance (CCEEB)
Earth Justice
Industry Coalition
Regulatory Flexibility Group (RegFlex)
Southern California Air Quality Alliance (SCAQA)
Western States Petroleum Association

Facilities
Air Products
California Portland Cement Company
Chevron
ExxonMobil
Owens Brockway
Paramount
Phillips66
Tesoro
Ultramar
Other facilities

Manufacturers of Control Devices & Consultants
BASF
BELCO
Cheng Low NOx
ClearSign
Cormetech
ETS
Elex CEMCAT
Grace Davidson
Great Southern Flameless
Haldor Topsoe
INTERCAT
MECS
Mitsubishi
NEC
Tri-Mer

Others
California Air Resources Board
Bay Area Air Quality Management District

Santa Barbara Air Pollution Control District
San Joaquin Valley Air Pollution Control District
U.S. Environmental Protection Agency

Chapter 1 – Background

Legislative Authority

The California Legislature created the SCAQMD in 1977 as the agency responsible for developing and enforcing air pollution control rules and regulations in the South Coast Air Basin (Basin). The H&SC requires the SCAQMD to adopt an AQMP outlining how the Basin will achieve and maintain state and federal ambient air quality standards by the earliest practicable date. In addition, the SCAQMD is required to adopt rules and regulations to implement the AQMP. The SCAQMD's rules and regulations must contain BARCT for existing sources. The SCAQMD staff is required to conduct a BARCT reassessment on a regular basis to capture the advancement in control technology and to ensure that RECLAIM facilities achieve the emission reductions that would have occurred under a command-and-control approach and that emission reductions from the program contribute to the Basin achieving the federal and state ambient air quality standards. The relevant H&S provisions, including a definition of BARCT, are cited below:

H&SC §40460(a): "*... the south coast district board shall adopt a plan to achieve and maintain the state and federal ambient air quality standard.*"

H&SC §40440(a): *"The south coast district board shall adopt rules and regulations that carry out the plan and are not in conflict with state law and federal laws and rules and regulations*."

H&SC §40440(b)(1): " *The rules and regulations adopted ... shall ... require the use of best available control technology for new and modified sources and the use of best available retrofit control technology for existing sources*."

H&SC §40406: "…*best available retrofit technology means 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.*"

Non-Attainment Status

Relative to the ozone and PM2.5 NAAQS promulgated by the U.S. EPA to protect public health and the environment, the Basin is currently classified as an "extreme" non-attainment area for ozone and is a non-attainment area for annual and 24-hour PM2.5. Scientific studies have found an associations between exposure to particulate matter and ozone and significant health problems, including asthma, chronic bronchitis, reduced lung function, irregular heartbeat, heart attack, and premature death in people with heart or lung disease. Individuals particularly sensitive to air pollution exposure include older adults, people with heart and lung disease, and children.

There are six criteria pollutants that contribute to ambient air pollution for which there are federal NAAQS: ozone, carbon monoxide, lead, particulate matter, sulfur dioxide, and nitrogen dioxide. The effect of reducing emissions of each of these pollutants varies by area depending on the composition of the atmosphere, concentrations of these pollutants and other area-specific factors. The federal EPA requires the SCAQMD to implement all reasonably available control measures (RACM) and reasonably available control technology (RACT) considering economic and technical feasibility and other factors to reduce criteria air pollutants.

On March 12, 2008, the EPA strengthened its ground-level 8-hour ozone standard from 0.08 ppm to a level of 0.075 ppm. On May 21, 2012, the EPA classified two areas in the country, the South Coast and the San Joaquin Valley, as "Extreme" non-attainment areas with respect to the 2008 8-hour ozone standard. The attainment dates for the 1997 and 2008 ozone standards are June 15, 2024 and July 20, 2032, respectively, with emission reductions and attainment required in the previous calendar year. NOx is a major precursor of ozone and PM2.5, and reducing NOx is essential for the Basin to attain the ozone ambient air quality standards while also helping to meet PM2.5 standards. The SCAQMD staff is currently developing the 2016 AQMP to address ozone and PM2.5 attainment strategies.

Control Measure CMB-01 of the 2012 AQMP

Control Measure CMB-01 – *Further NOx Reductions from RECLAIM* is one of the control measures specified in the 2012 AQMP. The control measure CMB-01 has 2 phases: Phase I has an estimated reduction of 2–3 tpd NOx and serves as a contingency measure for PM2.5 attainment. A contingency measure is a measure that will be automatically implemented if the basin fails to meet the PM2.5 standards by the attainment date. Based on recent data, the Basin will fail to meet the 24-hour PM2.5 ambient air quality standard by the original attainment date of 2014 as well as the revised attainment date of 2015. Therefore, the SCAQMD has asked EPA to reclassify the Basin as "serious" non-attainment for the 24-hour standard, and will be required to submit a new attainment plan. If Phase I was not triggered, CMB-01 anticipated that Phase I reductions would be rolled into Phase II to help attain the ozone standards. In combination, Phase I and Phase II together had estimated reductions of 3-5 tpd with the lower end of emission reduction range committed to in the State Implementation Plan (SIP) yet to be acted on by U.S. EPA. The adoption date and implementation date for Control Measure CMB-01 were estimated to be 2015 and 2020, respectively. The analysis done for these amendments resulted in significantly more reductions than those identified in the control measure. The control measure emission reduction estimates are based on information available at that time, and the emission reductions proposed for a rule that implements a control measure can be more or less than the control measure estimate based on additional analysis of available cost effective technologies. The control measure CMB-01 mentioned that additional reductions would be sought if required to implement BARCT, and that all feasible reductions are needed to attain the ozone standards.

Current NOx RECLAIM Program

On October 15, 1993, the SCAQMD's Governing Board adopted the RECLAIM program and Regulation XX. Regulation XX includes 11 rules that specify the applicability, NOx and SOx allocations, general requirements, as well as monitoring, reporting, and recordkeeping requirements. The RECLAIM program started with 392 NOx facilities in 1993, dropped to 281 facilities in 2011, with 275 facilities by end of the 2013 compliance year. Under the RECLAIM program, facilities are issued SOx and NOx annual allocations, also known as facility caps. The facility caps decline annually to reflect the levels of BARCT that were envisioned to be in place at the RECLAIM facilities. To meet their annual declining allocations, RECLAIM facilities have the flexibility of installing pollution control equipment, changing operations, or purchasing RECLAIM Trading Credits. It was envisioned that a BARCT analysis would be conducted periodically to capture the advancement in control technology and to assure that the RECLAIM program would achieve emission reductions equivalent to command and control approaches and as expeditiously as possible. Throughout the years, there have been a number of amendments to the RECLAIM rules, including BARCT reassessments for NOx in 2005 and SOx in 2010. As a result of the January 2005 amendment, NOx RTCs were reduced by 7.7 tpd, approximately 22.5%, applied all 281 RECLAIM facilities. This reduction was implemented in phases: 4 tpd by 2007 and an additional 0.925 tpd in each of the following 4 years. Figures 1.1 - 1.3 show the historical trend of NOx emissions, RTC allocations, and RTC price for compliance years 1994 - 2013 reflecting the fact that the NOx reductions specified by the January 2005 amendment did not upset the market or cause RTC prices to rise above the $15,000 per ton, which is the level specified in Rule 2015 that would require a program review.

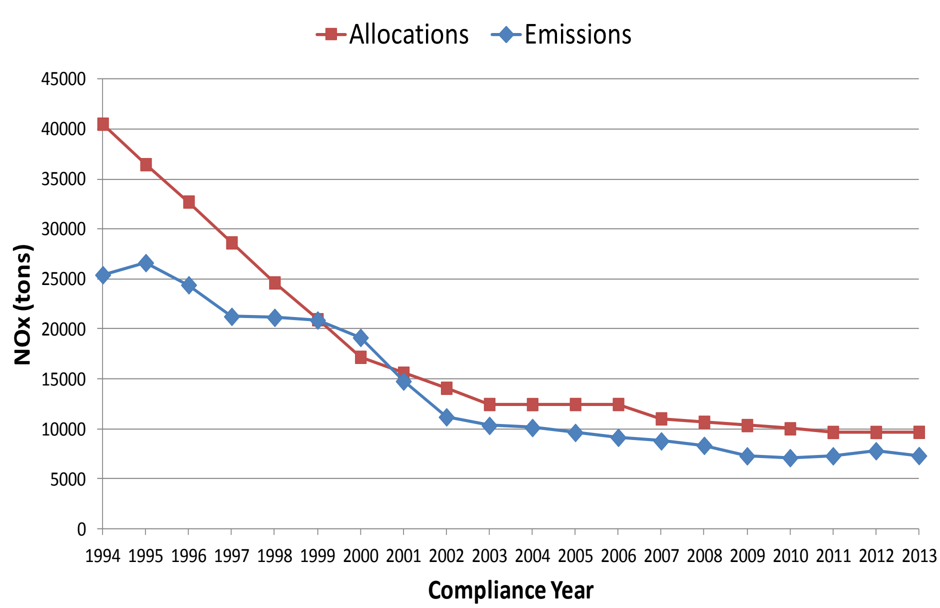


Figure 1. 2 – Audited Emissions and RTC Holdings

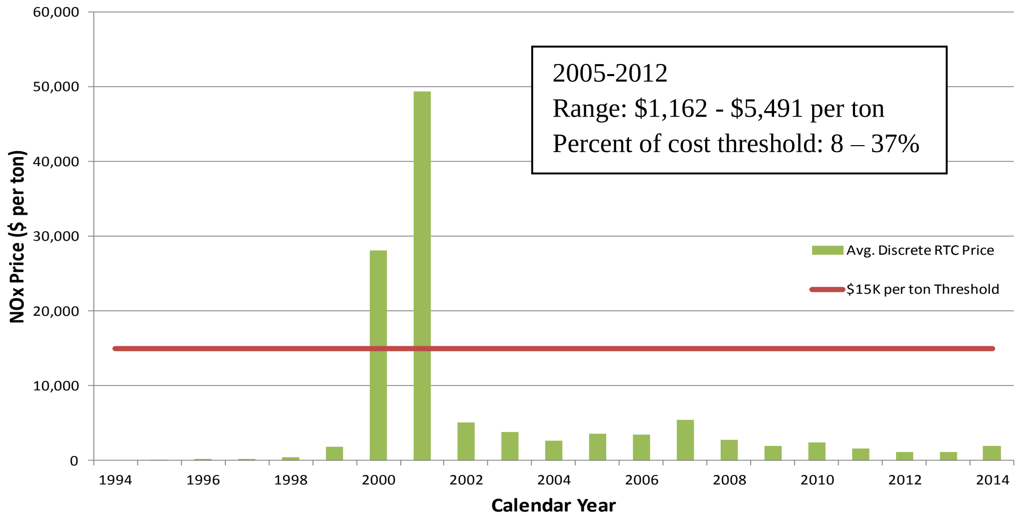
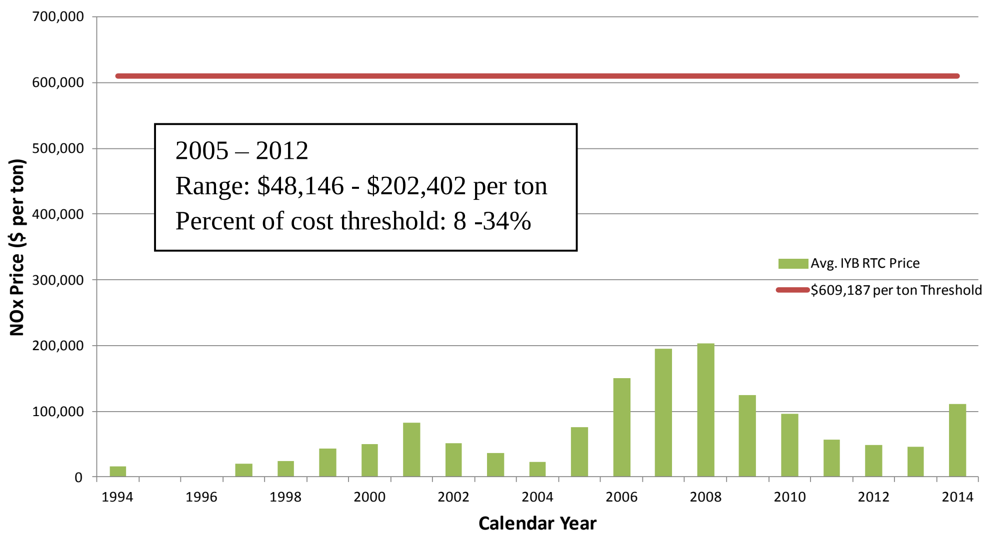


Figure 1.3 – NOx Discrete RTC Price versus Threshold



Note: IYB cost threshold is adjusted annually by CPI

Figure 1.4 – NOx Infinite Year Block (IYB) RTC Price versus Threshold

According to the RECLAIM Annual Audit Reports, the vast majority of the RECLAIM facilities complied with their NOx RTC allocations and their aggregate RECLAIM NOx emissions remained below their NOx allocations for each compliance year since 2005. RECLAIM facilities had a high rate of compliance for covering emissions with RTCs. The same was true for all other years of the program except for 2000 and 2001 when there was a California power crisis. The audited annual NOx emissions, NOx RTCs allocated for the universe, and unused RTCs are summarized in Table 1.1. Data show that approximately 21–30% RTCs in each of the past 5 years were not used, approximately 5.45 tpd – 8.41 tpd.

Table 1. 1 – Audited Emissions, RTC Holdings and Unused RTCs from 2009-2013

Compliance Year	Audited emissions (tons)	RTC Holdings (tons)	Unused RTCs (tons)	Unused RTCs (%)
2009	7,306	10,377	3,071	30%
2010	7,121	10,053	2,932	29%
2011	7,302	9,690	2,388	25%
2012	7,691	9,689	1,988	21%
2013	7,326	9,699	2,373	24%

Reference: Table 3-2, page 3-4, Annual RECLAIM Audit Report for 2013 Compliance Year

NOx RECLAIM Facilities

There were 281 facilities in RECLAIM as of June 2011 and 275 by the end of compliance year 2013. These facilities either elected to enter the program or had NOx emissions greater than or equal to four tons per year in 1990 or any subsequent year. The distribution of the 20 tpd audited 2011 emissions and the 26.5 tpd RTC allocations for 2020 are shown in Figures 1.5 and 1.6.

The top 37 facilities emitted 17.10 tpd NOx in 2011, more than 85% of emissions. The NOx emissions from RECLAIM facilities are generated from a wide range of equipment, and the top NOx emitting sources at the 37 facilities are refinery coke calciners, refinery fluidized catalytic cracking units, refinery and non-refinery gas turbines, refinery boilers and heaters, glass melting furnaces, sodium silicate furnaces, metal heat treating furnaces, internal combustion engines, and refinery sulfur recovery and tail gas incinerators. Cement kilns were the highest emitting stationary NOx source in 2008. The 2011 inventory did not include the cement kilns in the inventory since they were non-operational and subsequently shut down in 2012. However staff did identify a new BARCT level for this operation and removed the equivalent amount of emissions from the remaining emissions in 2023 from the cement kiln.

Figure 1.6 shows the amount of RTC holdings by sector for Compliance Year 2020 without considering 2015 BARCT levels and the proposed amendments. Refineries hold over half of the RTCs with the second most predominant RTC holding industry being electrical generating facilities.

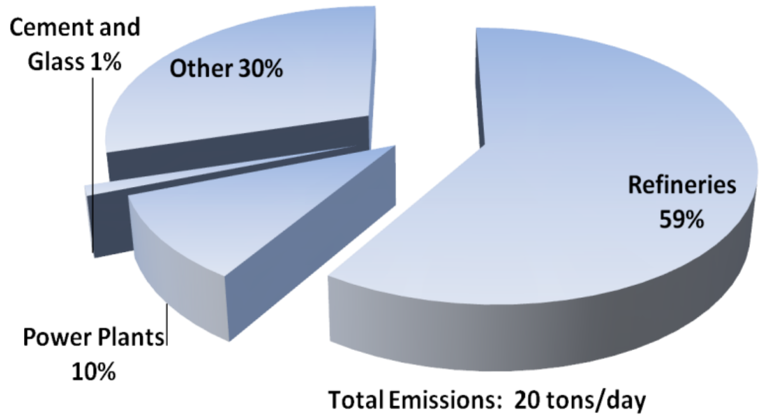


Figure 1. 5 – Distribution of 20 tpd NOx Emissions (End of Compliance Year 2011)

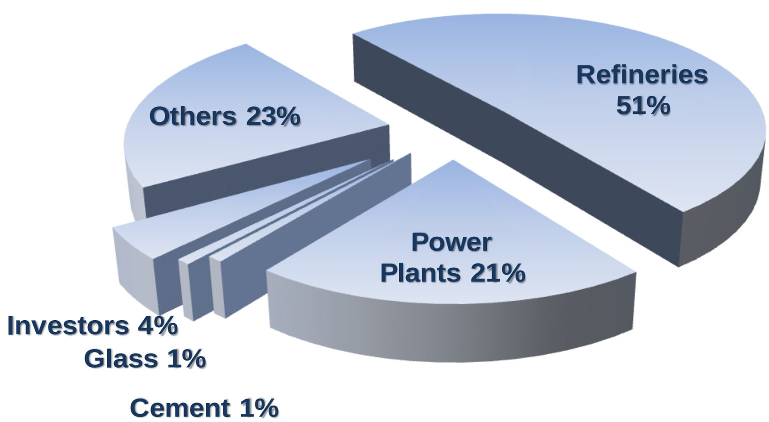


Figure 1. 6 – Distribution of 26.5 tpd RTC Holdings (End of Compliance Year 2020)

Chapter 2 – Facility Emissions and RTC Holdings

Projected Emissions and Emission Reductions

As stated in the 2012 AQMP and summarized in Table 2.1 below, NOx emissions from the RECLAIM facilities were projected to be about 27 tpd by 2023 (26.51 tpd total allocation rounded up to 27 tpd in the 2012 AQMP), representing 37% of the NOx emissions from stationary sources. Collectively, RECLAIM is the fourth largest source of NOx emissions in the Basin in 2023 as shown in Table 2.2.

The 3-5 tpd of reductions for CMB-01 were estimated during the development of the 2012 AQMP, however staff's analysis of BARCT shows that additional reductions from RECLAIM NOx sources are possible. Staff is proposing that the RECLAIM program can contribute 14 tpd additional NOx emissions reductions by 2023.

Table 2. 1 - Annual Average Emissions (tpd) by Major Source Category (2023 Base Year)

Source Category	**NOx**
Stationary Sources	
Fuel Combustion (non-RECLAIM)	27
Waste Disposal	2
Cleaning and Surface Coatings	0
Petroleum Production and Marketing	0
Industrial Processes	0
Solvent Evaporation	
Consumer Products	0
Architectural Coatings	0
Others	0
Misc. Processes	17
RECLAIM Sources	**27**
Total Stationary Sources	**73**
Total Mobile Sources	**255**
TOTAL	**328**

Reference: Table 3-6A, 2012 South Coast AQMP

Table 2. 2 - Top Ten Ranking of NOx Emissions from Highest to Lowest (2023 Base Year)

Rank	Sources
1	Heavy-Duty Diesel Trucks
2	Off-Road Equipment
3	Ships & Commercial Boats
4	NOx RECLAIM
5	Locomotives
6	Aircraft
7	Residential Fuel Combustion
8	Heavy-Duty Gasoline Trucks
9	Passenger Cars
10	Light-Duty Trucks

Reference: Table 3-10 of the 2012 South Coast AQMP

Audited Facility Emissions and RTC Allocations

The 281 RECLAIM facilities, as of June 2011, emitted 20.0 tpd NOx in 2011 adjusted to 20.7 tpd NOx using the electrical generating facilities' emissions in 2012 instead of 2011 emissions. Table 2.3 below lists the top 37 emitting facilities that contributed 17.10 tpd NOx emissions in 2011, more than 85% of the emissions from the entire NOx RECLAIM universe. The cement facility, the highest emitting NOx facility from 2008 to 2010, was not in operation in 2011.

At the beginning of the RECLAIM program, the NOx RECLAIM universe was granted 40,534 tons per year (111 tpd) RTCs. This original amount of RTCs gradually dropped to a level of 12,486 tons per year (34.2 tpd) in 2005. In 2005, the RECLAIM rules were amended to implement a BARCT assessment that resulted in a cumulative RTC reduction of 7.7 tpd that was fully implemented in 2011. For compliance year 2011 and beyond, the RTC holdings for the NOx universe remain at a constant level of 9,677 tons per year (26.5 tpd).

Table 2. 3 - NOx Audited Emissions (2011 Compliance Year)

			2011 Emissions (lbs)	2011 Emissions (tpd)
1	800089	EXXONMOBIL OIL CORPORATION	1,602,233	2.19
2	800030	CHEVRON PRODUCTS CO.	1,425,393	1.95
3	131003	BP WEST COAST PROD.LLC BP CARSON REF.	1,231,852	1.69
4	800436	TESORO REFINING AND MARKETING CO, LLC	1,171,965	1.61
5	171107	PHILLIPS 66 CO/LA REFINERY WILMINGTON PL	1,143,902	1.57
6	171109	PHILLIPS 66 COMPANY/LOS ANGELES REFINERY	673,652	0.92
7	800026	ULTRAMAR INC (NSR USE ONLY)	534,363	0.73
8	131249	BP WEST COAST PRODUCTS LLC,BP WILMINGTON	407,394	0.56
9	800183	PARAMOUNT PETR CORP (EIS USE)	104,249	0.14
10	151798	TESORO REFINING AND MARKETING CO, LLC	93,488	0.13
		Total Refineries		**11.49**
1	46268	CALIFORNIA STEEL INDUSTRIES INC	464,990	0.64
2	800128	SO CAL GAS CO (EIS USE)	461,243	0.63
3	166073	BETA OFFSHORE	391,977	0.54
4	171960	TIN, INC. DBA INTERNATIONAL PAPER	327,637	0.45
5	18931	TAMCO	226,012	0.31
6	800074	LA CITY, DWP HAYNES GENERATING STATION	205,022	0.28
7	160437	SOUTHERN CALIFORNIA EDISON	204,132	0.28
8	800193	LA CITY, DWP VALLEY GENERATING STATION	166,413	0.23
9	4242	SAN DIEGO GAS & ELECTRIC	142,751	0.20
10	4477	SO CAL EDISON CO	137,290	0.19
11	7427	OWENS-BROCKWAY GLASS CONTAINER INC	135,486	0.19
12	119907	BERRY PETROLEUM COMPANY	131,857	0.18
13	129816	INLAND EMPIRE ENERGY CENTER, LLC	105,857	0.15
14	800075	LA CITY, DWP SCATTERGOOD GENERATING STN	103,988	0.14
15	115389	AES HUNTINGTON BEACH, LLC	98,993	0.14
16	51620	WHEELABRATOR NORWALK ENERGY CO INC	89,025	0.12
17	5973	SO CAL GAS CO	88,258	0.12
18	11435	PQ CORPORATION	81,270	0.11
19	115394	AES ALAMITOS, LLC	80,929	0.11
20	800335	LA CITY, DEPT OF AIRPORTS	73,245	0.10
21	129497	THUMS LONG BEACH CO	66,364	0.09
22	124838	EXIDE TECHNOLOGIES	62,824	0.09
23	15504	SCHLOSSER FORGE COMPANY	52,331	0.07
24	128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA	49,983	0.07
25	800330	THUMS LONG BEACH	49,657	0.07
26	114801	RHODIA INC.	48,878	0.07
27	22911	CARLTON FORGE WORKS	48,839	0.07
		Total non-refineries		**5.61**
		Total for top 37 emitting facilities		**17.10**

Major NOx Sources at Top Emitting Facilities

RECLAIM Rule 2012 establishes the requirements for monitoring, reporting and recordkeeping of NOx emissions under the RECLAIM program and classifies the NOx emitting equipment at the RECLAIM facilities into three categories: major NOx sources, large NOx sources, and NOx process units. RECLAIM facilities are required to monitor the emissions for each major NOx source with a Continuous Emissions Monitoring System (CEMS) and report the emissions electronically on a daily basis via a remote terminal unit to the SCAQMD Central Station. The emissions for each large source are calculated based on fuel usage or exhaust gaseous flow rates and reported electronically on a monthly basis to the SCAQMD Central Station. The emissions from all process units are reported on a quarterly basis.

Table 2.4 shows that major NOx sources contributed 88% of the NOx emissions from the NOx RECLAIM universe; large NOx sources and process units generated only 12% of the NOx RECLAIM emissions. Thus, staff focused on the major NOx sources at the top 37 emitting facilities to evaluate potential BARCT and emission reductions.

The major NOx sources at the top 37 emitting RECLAIM facilities subject to new 2015 BARCT analysis are refinery fluid catalytic cracking units, refinery boilers and heaters >40 mmbtu/hr, refinery and non-refinery gas turbines, cement kilns, glass melting furnaces, sodium silicate furnaces, metal heat treating furnaces >150 mmbtu/hr, refinery sulfur recovery and tail gas incinerators, and internal combustion engines.

Table 2. 4 - NOx Emissions per Source Classification

Source Categories	NOx (tons per day)	Number of Equipment	Percentage of Emissions
Major NOx Sources	17.5	415	88%
Large sources and Process Units	2.6	>1000	12%
Total	**20.0**		**100%**

Chapter 3 – 2015 Proposed BARCT and Emission Reductions

Previous BARCT Determinations

At the inception of the RECLAIM program, NOx starting allocations for 1994 and ending allocations for 2000 were based on the starting and ending emissions factors listed in Table 1 of Rule 2002 – *Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx)*. For the 2003 ending allocations, 2000 ending allocations were adjusted to be equal to the 1991 AQMP projected inventory for RECLAIM sources in 2003. The 2005 future year allocations were set equal to the 2003 allocations. In 2005, the SCAQMD staff conducted a BARCT assessment, and the rules were amended to reduce the RTCs by 7.7 tpd implemented by 2011. Table 3 of Rule 2002 was added to record the 2005 BARCT levels. The BARCT levels were kept at the 2000 ending emission factors as shown in Table 2 of Rule 2002 for individual equipment categories where improved control technologies were not yet deemed applicable or cost-effective in the 2005 BARCT assessment.

Proposed 2015 BARCT

Staff is proposing the BARCT levels tabulated in Table 3.1 and estimating that these 2015 BARCT levels will provide about 8.8 tpd in NOx emission reductions (6.00 tpd for refinery sector and 2.77 tpd for non-refinery sector) beyond what could be achieved by the 2005 BARCT levels for each category of major emitting sources at the top emitting facilities. Further discussions of NOx control technologies, proposed BARCT levels, estimated emission reductions, costs and cost effectiveness values are discussed in Part I of this staff report for the refinery sector and Part II for the non-refinery sector. The RTC reductions to implement BARCT are 14 tpd. See Chapter 5 and Part III of this staff report.

Part I – BARCT Analyses for Refinery Sector:

Appendix A	Fluid Catalytic Cracking Units
Appendix B	Boilers and Heaters, >40-100 mmbtu/hr
Appendix C	Refinery Gas Turbines
Appendix D	Coke Calciner
Appendix E	Sulfur Recovery Units Tail Gas Incinerators

Part II – BARCT Analyses for Non-Refinery Sector:

Appendix M	Cement Kilns
Appendix N	Container Glass Melting Furnaces
Appendix O	Sodium Silicate Furnace

Appendix P	Metal Melting Furnaces > 150 mmbtu/hr
Appendix Q	Non-Refinery Gas Turbines
Appendix R	Non-Refinery, Non-Electrical Generating Facility Internal Combustion Engines
Appendix S	Non-Refinery Boilers > 40 mmbtu/hr

Table 3. 1 - 2015 Proposed BARCT Levels and Emission Reductions

Refinery Sector	2015 BARCT Level	Incremental Emission Reductions Beyond 2000/2005 BARCT (tpd)
Fluid Catalytic Cracking Units	2 ppmv at 3% O2	0.43
Boilers and Heaters >40 mmbtu/hr	2 ppmv or 0.002 lb/mmbtu	0.94
Gas Turbines	2 ppm at 15% O2	4.14
Coke Calciner	10 ppmv at 3% O2	0.17
Sulfur Recovery Units Tail Gas Incinerators	2 ppmv at 3% O2 or 95% reduction	0.32
	Total	**6.00**

Non-refinery Sector	2015 BARCT Level	Incremental Emission Reductions Beyond 2000/2005 BARCT (tpd)
Cement Kilns	0.5 lb/ton clinker	1.29 (note)
Container Glass Melting Furnaces	80% reduction	0.24
Sodium Silicate Furnace	80% reduction	0.09
Heat Treating Furnaces >150 mmbtu/hr	9 ppmv at 3% O2	0.56
Gas Turbines (non-OCS)	2 ppmv at 15% O2	1.04
ICEs (non-OCS)	11 ppmv at 15% O2	0.84
	Total	**2.77**

Note: The 1.29 tpd emission reductions from cement kilns were not included in the 2.77 tpd emission reductions because the cement facility was not in operation in 2011. Cement kilns were the highest source of NOx emissions in 2008, thus staff conducted a BARCT analysis for cement kilns and reduced the remaining emissions projected to the 2023 level for the cement facility to the BARCT level.

Co-Benefits of Energy Efficiency Projects

For the refinery sector, in addition to the 6.00 tpd emission reductions shown in Table 3.1, there are about 0.6 to 0.7 tpd NOx emission reductions that are expected to have occurred concurrently with the energy efficiency projects to reduce greenhouse gases as shown in Table 3.2. According to CARB staff, these co-benefits reductions were not yet included in the baseline and SCAQMD staff did not include the co-benefits in this proposal. See Appendix K for further details.

Table 3. 2 - Co-Benefits of Emission Reductions for Energy Efficiency Projects

Projects	Emission Reductions (tpd)
Completed and ongoing (2007-2011)	0.6
Scheduled	0.05
Under investigation	0.07 - 0.08
Total	**0.7**

Chapter 4 – Costs and Cost Effectiveness

This chapter discusses both the preliminary analysis in December 2014 and the revised analysis in 2015.

Staff's Preliminary Estimates

Staff preliminary analyses as of December 2014 for costs and cost effectiveness are discussed in Part I, Appendices A – E, for the refinery sector and Part II, Appendices M – S, for the non-refinery sector, respectively. A summary of the methods used for costs and cost effectiveness analyses and the results of these detailed analyses are provided in this Chapter.

The Present Worth Values (PWV) of a control device are the total costs to install and operate the control device estimated at the present currency value. The PWV consists of the Total Installed Costs (TIC) and Annual Operating Costs (AC) during the entire economic life of the control equipment using the Discounted Cash Flow (DCF) Method as follows:

$$PWV = TIC + (15.62 \times AC)$$

Where:

PWV = Present Worth Value, $
TIC = Total Installed Costs, $
AC = Annual Operating Costs, $
15.62 = a factor to estimate the cumulative annual operating costs during a 25-year life of a control device

The incremental cost effectiveness value of a control device is estimated as follows:

$$CE_{\text{incremental}} = (PWV_{\text{2015 BARCT}} - PWV_{\text{2000/05 BARCT}}) / (ER_{\text{2015 BARCT}} - ER_{\text{2000/05 BARCT}})/25/365$$

Where:

$CE_{\text{incremental}}$ = Incremental Cost Effectiveness, $/ton
$PWV_{\text{2015 BARCT}} - PWV_{\text{2000/05 BARCT}}$ = Incremental costs to achieve additional control to meet the 2015 BARCT level from the 2000/2005 BARCT level
$ER_{\text{2015 BARCT}} - ER_{\text{2000/05 BARCT}}$ = Incremental emission reductions to achieve the 2015 BARCT level from the 2000/2005 BARCT level

The incremental costs and cost effectiveness were calculated based on the 2011-2012 baseline emissions and the DCF method. Staff also presented the cost effectiveness estimated with the

Levelized Cash Flow (LCF) method. In the cost effectiveness analysis using the DCF method, staff used a cutoff level of $50,000 per ton. The $50,000 per ton cutoff is based on the policy developed during the 2008 – 2010 SOx RECLAIM rule amendment that was adopted by the District Governing Board. The results of staff's preliminary estimates in 2014 for PWVs and cost effectiveness values are summarized in Tables 4.1 and 4.2; and the revised estimates are summarized in Tables 4.3 and 4.4.

Consultants' Estimates

In the Fall of 2014, the SCAQMD staff contracted with two consultants, NEC and ETS, to conduct independent studies on costs and cost effectiveness. The consultants' reports are included as separate documents (Addenda 1 and 2). Table 4.1 below shows a comparison between staff's and NEC's estimates for the refinery sector, and Table 4.2 shows a comparison between staff's and ETS's estimates for the non-refinery sector.

Refinery Sector

For the refinery sector, as shown in Table 4.1, NEC and staff recommended BARCT levels of 2 ppmv for gas turbines, FCCUs, boilers/heaters, and SRU/TG incinerators. For the refinery coke calciner, NEC recommended a BARCT level of 5 - 10 ppmv instead of 2 ppmv previously recommended by staff. Staff agreed with NEC's recommendation and changed the recommendation to 10 ppmv BARCT for the coke calciner. Different approaches were used to estimate the SCR costs for FCCUs, boilers/heaters and SRU/TG incinerators, an adjustment was made to the proposed shave amount to account for the different engineering and cost assumptions. Please refer to Part I, Appendix F - J, for further discussion. Table 4.3 shows the ranges of PWVs and cost effectiveness values for the refinery sector based on the revised proposal.

Table 4. 1 – Initial Proposal - BARCT Levels, Costs and Cost Effectiveness - Refinery Sector (December 2014)

Equipment Category	Proposed 2014 BARCT	Staff's Estimates		Estimates Using NEC's Information		Incremental DCF Cost-Effectiveness
		Incremental Reductions (tpd)	**PWVs ($M)**	**Incremental Reductions (tpd)**	**PWVs ($M)**	**$/ton NOx Reduced**
Gas Turbines	2 ppmv	4.14	97.7	4.14	52.7	1K - 3K
FCCUs	2 ppmv	0.43	152	0.43	211	3K - 18K
Coke Calciner	5 ppmv	0.21(1)	22 - 61	0.17(2)	39.5	11K - 25K
Boilers/Heaters >40 mmbtu/hr	2 ppmv	1.05	254.5	0.61	162	27K - 29K
SRU/TG Incinerators	2 ppmv	0.35	49 - 68	0.32	120	15K - 48K
Total		**6.18**	**575 - 633**	**5.67**	**585**	**7K - 12K (3)**

Note: 1) Based on 5 ppmv BARCT, 2) Based on 10 ppmv BARCT, 3) Weighted average by NOx reductions

Non-Refinery Sector

For the non-refinery sector, ETS agreed with the proposed BARCT levels recommended for all categories. ETS's estimated costs and incremental costs were slightly higher than staff's estimates as shown in Table 4.2. Table 4.4 shows the revised ranges of PWVs and cost effectiveness values for the non-refinery sector.

Table 4. 2 – Initial Proposal - BARCT Levels, Costs and Cost Effectiveness - Non-Refinery Sector (December 2014)

	Proposed 2014 BARCT	Incremental Reductions (tpd)	Staff's PWVs ($M)	ETS's PWVs ($M)	Incremental DCF CE $/ton NOx Reduced
Cement Kilns	0.5 lb/ton clinker	1.32	34 - 107	36 - 112	3 - 10K
Container Glass	0.24 lb/ton pulled	0.24	4 - 14	6 - 15	3 - 7K
Sodium Silicate Furnace	1.28 lb/ton pulled	0.09	2.8 - 4.6	3 - 4.6	4 - 6K
Metal Heat Treating Furnaces >150 mmbtu/hr	9 ppmv @ 3% O2	0.56	8 - 10	8 - 10	3 - 3.8 K
Gas Turbines	2 ppmv @15% O2	1.04	3 - 14	3 - 14	5 - 36K
ICEs	11 ppmv @15% O2	0.84	0.9 - 4	0.9 - 4	5 - 8K
Boilers >40 mmbtu/hr	No new BARCT	0	0	0	
Total		**6.18**	**53 - 154**	**57 - 160**	**4 - 15 K** (1, 2)

Note: 1) LCF ranges from $5 K - $57 K per ton, 2) Weighted average by NOx reductions

Staff Recommendations

After the facility visits and the consultants' analyses were completed, staff revisited the cost estimations and made modifications to the preliminary proposals. Staff's revised recommendations are presented below.

Refinery Sector

Staff's current recommendations for the refinery sector are tabulated in Table 4.3. Please refer to Part I, Appendices A-J for additional information.

Table 4. 3 - Staff's Revised Recommendation for Refinery Sector (May 2015)

	2015 BARCT	Incremental Reductions (tpd)	PWVs ($M)	Incremental Cost Effectiveness ($K/ton DCF)	Note
FCCUs	2 ppmv	0.43	152 – 391	3 – 13	1
Gas Turbines	2 ppmv	4.14	53 – 98	1 – 3	2
Boilers/Heaters >40 mmbtu/hr	2 ppmv	0.94	237	28	3
Coke Calciner	10 ppmv	0.17	40 - 91	19 – 25	4
SRU/TG Incinerators	2 ppmv	0.32	83 - 106	28 – 40	5
Total		**6.00**	**565 – 923**	**10 – 17**	6

Notes:

1) See Appendix A. The PWV of $152M are for the case where all 5 refineries would install SCRs. The PWV of $391 M are for the case where SCRs would be installed at Ref 5 and 6 and LoTOx and scrubbers at Ref 4, 7 and 9 to reduce both NOx and SOx.
2) See Appendix C. The PWV of $53 M was estimated by NEC for adding catalysts to all SCRs. The PWV of $98 M was derived by SCAQMD staff for adding catalysts to Ref 1's SCRs and new SCRs to Ref 4 - 7.
3) See Appendix B.
4) See Appendix D. The PWV of $40M was estimated by NEC for LoTOx technology and $91 M was staff's estimates for Tri-Mer technology
5) See Appendix E. The PWV of $83 M was for SCRs and $106 M for LoTOx applications
6) Incremental cost effectiveness is the weighted average by NOx reductions. Low end of incremental cost effectiveness = $565 M/ (6*25*365) = $10,320 per ton NOx reduced. High end of incremental cost effectiveness = $923 M/ (6*25*365) = $16,858 per ton NOx reduced.

Non-Refinery Sector

Table 4.4 tabulates staff's current recommendations for the non-refinery sector. Please refer to Part II, Appendices M-R for further information.

Table 4. 4 - Staff's Recommendation for Non-Refinery Sector (May 2015)

	2015 BARCT	Incremental Reductions (tpd)	PWVs ($M)	Incremental Cost Effectiveness ($K/ton DCF)	Note
Cement Kilns	0.5 lb/ton clinker	1.29	61 - 152	5 - 11	1
Container Glass Melting Furnaces	0.24 lb/ton glass pulled	0.24	6 - 15	3 - 7	2
Sodium Silicate Furnace	1.28 lb/ton glass pulled	0.09	3.0 - 4.6	4 - 8	3
Metal Heat Treating Furnace > 150 mmbtu/hr	9 ppmv at 3% O2	0.56	8 - 10	3 - 3.8	4
Gas Turbines	2 ppmv at 3% O2	1.04	~109	5 - 36	5
ICEs	11 ppmv at 15% O2	0.84	~37	5 - 8	6
	Total	**4.06**	**224 - 328**	**6 - 9**	7, 8, 9, 10

Note:

1) Refer to Appendix M
2) Refer to Appendix N
3) Refer to Appendix O
4) Refer to Appendix P
5) Refer to Appendix Q
6) Refer to Appendix R
7) Incremental costs effectiveness is the weighted average by NOx reductions. With cement kilns: low end of incremental cost effectiveness = $224 M/ (4.06*25*365) = $6 K per ton NOx reduced, and high end of incremental cost effectiveness = $328 M/ (4.06*25*365) = $9 K per ton NOx reduced.
8) The incremental emission reductions would be 4.06 tpd including the incremental reductions for the cement kilns. Without the cement kilns, the incremental emission reductions would be 2.77 tpd.
9) The range for PWVs would be $224 M – $328 M including the PWVs for the NOx control device for cement kilns. The range of PWVs would be $163 M - $176 M without the control devices for cement kilns.
10) Incremental costs effectiveness is the weighted average by NOx reductions. Without cement kilns: low end of incremental cost effectiveness = $163 M/ (2.77*25*365) = $6 K per ton NOx reduced, and high end of incremental cost effectiveness = $176 M/ (2.77*25*365) = $7 K per ton NOx reduced.

Chapter 5 - RTC Reductions

Remaining Emissions

As discussed in the Public Process section, staff started the discussion with stakeholders on the calculation method that would be used to estimate the RTC reductions in 2013. One of the parameters used in the calculation for the RTC reductions is the remaining emissions projected to 2023. The 2023 remaining emissions estimates by staff were first presented to the stakeholders at the January 22, 2014 Working Group Meeting. Staff later refined the numbers and presented them to the stakeholders in the July 31, 2014 and April 29, 2015 Working Group Meetings. The changes made are summarized below.

Refinery Sector

Table 5.1 tabulates the estimated 2023 remaining emissions for each NOx source category in the refinery sector. In 2014, staff estimated the total 2023 remaining emissions to be 2.56 tpd. In 2015, staff revised the number to 2.76 tpd as a result of the following changes:

- The BARCT level for coke calciner was changed from 2 ppmv to 10 ppmv. As a result, the remaining emissions for coke calciner increased to 0.08 tpd.

- The costs of control for boilers/heaters and SRU/TG incinerators were revised to be higher. As a result, the cost effectiveness for several boilers/heaters and one incinerator became higher than the policy threshold of $50,000 per ton, and these units were excluded from the equipment that contributed to the emission reductions. The remaining emissions for the boilers/heaters >40 mmbtu/hr increased to 0.85 tpd, and the remaining emissions for the SRU/TG incinerators increased to 0.11 tpd.

Table 5. 1 - Remaining Emissions for Refinery Sector

	Total No of Units	2011 Emissions (tpd)	2000/2005 BARCT	2011 Emissions at 2000/2005 BARCT (tpd)	2015 BARCT	2011 Emissions at 2015 BARCT (tpd)	2023 Emission Reductions Beyond 2000/2005 BARCT (tpd)	2023 Emission at 2015 BARCT with GF = 1 (tpd)
FCCUs/CO Boilers	8	1.08	85% control	0.60	2 ppmv	0.17	0.43	0.17
Turbines/Duct Burners	21	1.33	62.27 lbs/mmcft	4.86	2 ppmv	0.72	4.14	0.72
Coke Calciner	2	0.55	30 ppmv	0.25	10 ppmv	0.08	0.17	0.08
SRU/TG Incinerators	17	0.43	RV	0.43	2 ppmv (or 95% control)	0.11	0.32	0.11
Boilers/Heaters > 110 mmbtu/hr	73	4.88	5 ppmv	0.82	2 ppmv	0.38	0.44	0.38
Boilers/Heaters >40-110 mmbtu/hr	69	2.00	25 ppmv	0.97	2 ppmv	0.47	0.50	0.47
Boliers/Heaters 20-40 mmbtu/hr	52	0.45	9 ppmv	0.10	n/a	0.10	0.00	0.10
Boilers/Heaters <20 mmbtu/hr	18	0.06	12 ppmv	0.02	n/a	0.02	0.00	0.02
Other Major/Large Sources	5	0.11	n/a	0.10	n/a	0.10	0.00	0.10
Other Process Units	n/a	0.60	n/a	0.60	n/a	0.60	0.00	0.60
Total	**265**	**11.50**		**8.76**		**2.76**	**6.00**	**2.76**

Non-Refinery Sector

Table 5.2 tabulates the estimated 2023 remaining emissions for each NOx source category in the non-refinery sector. In 2014, staff estimated the 2023 remaining emissions for the non-refinery sector to be 8.77 tpd. In 2015, staff revised the number to 7.47 tpd as a result of the following changes:

- The baseline for electrical generating facilities was changed from 2011 to 2012. The 2011 and 2012 baseline emissions were 1.45 tpd and 2.50 tpd, respectively. Staff also used either the BACT level or the level stated in the permit conditions to estimate the emission reductions beyond the levels that could be achieved by the 2005 BARCT. In addition, staff used the most recent growth factor of 0.868 to estimate the remaining emissions for the electrical generating facilities. As a result of these changes, the 2023 remaining emissions for electrical generating facilities were changed to 2.04 tpd.

- The remaining emissions from non-electrical generating facilities were changed to 1.37 tpd; and

- The remaining emissions from other sources were changed to 4.06 tpd.

Table 5. 2 - Remaining Emissions for Non Refinery Sector (May 2015)

POWER PLANTS*	# of Facilities	2012 Emissions (tpd)	2000/2005 BARCT	2012 Emissions at BARCT/BACT (tpd)	2015 BARCT	2012 Emissions at 2015 BARCT (tpd)	Emission Reductions Beyond 2005 BARCT (tpd)	Growth Factor	2023 Emissions at 2015 BARCT (tpd)
TOTAL	**30**	**2.50**	**P/O or BACT level**	**2.35**	**No new BARCT**	**2.35**	**0**	**0.8683**	**2.04**
NON-POWER PLANTS	**# of Units**	**2011 Emissions (tpd)**	**2000/2005 BARCT**	**2011 Emissions at 2000/2005 BARCT (tpd)**	**2015 BARCT**	**2011 Emissions at 2015 BARCT (tpd)**	**Emission Reductions Beyond 2005 BARCT (tpd)**	**Growth Factor**	**2023 Emissions at 2015 BARCT (tpd)**
Boilers	16	0.08	9-12 ppm	0.07	No new BARCT	0.07	0	0.96	0.07
Heaters	3	0.01	60 ppm	0.01	No new BARCT	0.01	0	0.93	0.01
Furnaces >150 MMBTU/hr	2	0.49	45 ppm	0.70	9 ppm	0.14	0.56	0.93	0.13
Furnaces	10	0.31	45 ppm	0.31	No new BARCT	0.31	0	0.93	0.29
Glass Melting Furnaces	2	0.30	1.2 lb/ton	0.30	80% Reduction	0.06	0.24	1.18	0.07
Sodium Silicate Furnace	1	0.11	6.4 lb/ton	0.11	80% Reduction	0.02	0.09	1.21	0.02
Gas Turbines (non-OCS)	14	1.43	61.45 lb/mmcf	1.24	2 ppm	0.21	1.04	1.10	0.23
Gas Turbines (OCS)	6	0.49	61.45 lb/mmcf	0.12	No new BARCT	0.12	0	1.46	0.18
ICEs (non-OCS)	25	0.35	217.36 lb/mmcf	1.05	11 ppm	0.21	0.84	1.03	0.22
ICEs (OCS)	6	0.03	217.36 lb/mmcf	0.11	No new BARCT	0.11	0	1.46	0.16
*Cement Kilns***	*2*	*1.61*	*2.73 lb/ton*	*1.61*	*0.5 lb/ton*	*0.32*	*1.29*	*0.9*	*0.29*
TOTAL	**87**	**3.60**		**4.02**		**1.26**	**2.77**		**1.37**
Other Sources* **		**3.12**		**3.12**		**3.12**			**4.06**
TOTAL NON-REFINERY		**9.22**		**9.49**		**6.73**	**2.77**		**7.47**

***This includes all power plants in RECLAIM. Calendar year 2012 AER reported fuel usage was used to calculate emissions at BARCT/BACT level.**

****CPCC's emissions and emission reductions have NOT been included in the totals, this facility did not have any emissions in CY2011. CY2008 emissions were used to calculate the emission reductions.**

*****Includes Non-Refinery, Non-Power Plant Process Units in the Top 37 and all other sources outside the Top 37.**

Calculation Method for RTC Reductions

The RTC reductions are calculated as follows:

RTC Reductions = RTC Holdings – (Remaining Emissions x Compliance Margin)

Where

RTC Holdings = 26.5 tpd
Remaining Emissions = ($R_{Refinery}$ + $R_{Non\text{-}Refinery}$ + $R_{Adjustment}$)
$R_{Refinery}$ = Remaining emissions for refinery sector x Growth Factor
$R_{Non\ Refinery}$ = Remaining emissions for non-refinery sector x Growth Factors
$R_{Adjustment}$ = Potential adjustments set aside for new electrical generating facilities
Compliance margin = 10% as provided in the previous RECLAIM amendments

An example shown below was presented at the April 29, 2015 Working Group Meeting:

$R_{Refinery}$ = 2.76 tpd including growth factor of 1 as shown in Table 5-1
$R_{Non\ Refinery}$ = 7.47 tpd including growth factor of 1.1 as shown in Table 5-2
$R_{Adjustment}$ = 0.07 tpd potential adjustments for new electrical generating facilities due to SONGS shutdown and 0.29 and 0.10 for CPCC and other shutdown facilities
RTC Reductions = 26.5 – ([(2.76 + 7.47 + 0.07) x 1.1] + (0.29 + 0.10))
= 26.5 – 11.7 = 14.8 tpd

Regional NSR Holding Account for Electrical Generating Facilities

Staff has received input from several electrical generating operators that have concerns with concurrent compliance with the RTC allocation shave and the new source review (NSR) holding requirements per Rule 2005. New facilities that entered into RECLAIM after October 15, 1993 must hold RTCs for all of their equipment at the permitted potential to emit (PTE) level at the beginning of every compliance year. Pre-RECLAIM power producing facilities only need to hold RTCs for one year if their PTEs increase, unless their new PTEs exceed their initial 1993 allocation. Electrical producing facilities often operate at a capacity factor well below the PTE level during any given compliance year. The combustion equipment for these facilities is also already at the BARCT or BACT emission level. These facilities would be shaved and be subject to complying with the NSR holding requirements as well as their annual emission reconciliation requirements.

Staff has proposed the creation of a Regional NSR Holding Account to help address the NSR holding requirements programmatically for all post-1993 electrical producing facilities. This account would reduce the individual facility NSR hold requirements by the amount that they were shaved and would be comprised of the shaved RTCs from these facilities as discrete credits. All electrical generating facilities would be allowed to access this account to offset emissions (rather than just satisfy NSR holding requirements) if the Governor of California declares a state of emergency regarding reliable energy supply or grid stability in the Basin. The size of the Regional NSR Holding Account would be equivalent to the RTCs shaved from the affected post-1993 electrical generating facilities. This approach serves two purposes. First, it provides relief from the different and burdensome NSR holding requirements for these newer facilities relative to older electrical generation facilities. Second, it provides an emergency source of RTCs to be accessed in the case of a power crisis. Any new electrical generating facility that enters RECLAIM after the proposed amendment would still be subject to the full multi-year NSR holding requirements.

Staff Proposal and CEQA Alternatives

Table 5.3 summarizes the staff proposal which includes a NOx RTC shave of 14 tpd rather than the 14.8 tpd calculated above. The 0.8 tpd difference is to account for comments received from stakeholders regarding uncertainties in the BARCT analysis, and to provide some additional compliance margin. Staff is currently proposing that the 14 tpd RTC reductions be distributed to 56 facilities and investors that collectively hold about 90% of the 26.5 tpd RTCs. The 56 affected facilities include 9 major refineries, 21 electrical generating facilities, and 26 other top emitting facilities as shown in Table 5.5. Staff is proposing not to shave the remaining 219 facilities that hold only 10% of the 26.5 tpd RTCs because there was limited or no new BARCT identified for other types of equipment and operations there. Other approaches to determine the RTC reductions as shown in Table 5.4 were analyzed as project alternatives in the CEQA analysis. For further information, please refer to Part III, Appendix U of this staff report.

Staff is proposing the following implementation schedule:

2016: 4 tons per day
2018: 2 tons per day
2019: 2 tons per day
2020: 2 tons per day
2021: 2 tons per day
2022: 2 tons per day

As shown in Table 1-1 of Chapter 1, in the past five years from 2009-2013, the unused RTCs in the NOx RECLAIM program ranged from 5.5 to 8 tpd, and thus staff is proposing a reasonable initial 4 tpd RTC reduction in 2016. Additional BARCT implementation will take about 2 – 4 years for planning, permitting, and construction, and staff is proposing that the remaining shave of 10 tpd take place between 2018 and 2022.

Table 5. 3 - Staff Proposal - Affected Facilities and Percent Shave

	Major Refineries and Investors	Non-Electrical generating facilities	Electrical generatin g facilities	Bottom 10% of RTC Holders	Total
No of facilities	9	26	21	219	275
Current RTCs	14.6	9.1		2.8	26.5
RTC Reductions	9.6	4.4		0	**<u>14.0</u>**
Remaining RTCs	5	4.7		2.8	12.5
Percent Shave	9.6/14.6 = 66%	4.4/9.1 = 49%		0%	

Note that investors are counted as one facility and grouped with the refineries.

Table 5. 4 - Alternatives for CEQA Analysis

	Alternative	Major Refineries + Investors	Non-Major Refineries/ Facilities	Electrical Generating Facilities	Bottom 10% of RTC Holders
1	Shave 14 tpd uniformly across all 275 facilities	53%	53%	53%	53%
2	Shave 15.87 tpd (w/o 10% compliance margin) uniformly across all 275 facilities	60%	60%	60%	60%
3	Shave 8.8 tpd (the difference in emission reductions between previous BARCT and 2015 BARCT) uniformly across all 275 facilities	33%	33%	33%	33%
4	No project	0%	0%	0%	0%
5	Shave 14 tpd weighted by BARCT reduction contribution and distributed to all 275 facilities	66%	37%	37%	37%

Table 5. 5 - List of Facilities and Investors that would have RTCs Reduced

Facility ID	Name
800030	CHEVRON PRODUCTS CO.
800089	EXXONMOBIL OIL CORPORATION
174655	TESORO REFINING & MARKETING CO, LLC
800436	TESORO REFINING AND MARKETING CO, LLC
171107	PHILLIPS 66 CO/LA REFINERY WILMINGTON PL
800026	ULTRAMAR INC
115394	AES ALAMITOS, LLC
115663	EL SEGUNDO POWER, LLC
800074	LA CITY, DWP HAYNES GENERATING STATION
800128	SO CAL GAS CO
800075	LA CITY, DWP SCATTERGOOD GENERATING STN
46268	CALIFORNIA STEEL INDUSTRIES INC
115536	AES REDONDO BEACH, LLC
160437	SOUTHERN CALIFORNIA EDISON
171109	PHILLIPS 66 COMPANY/LOS ANGELES REFINERY
174591	TESORO REF & MKTG CO LLC,CALCINER
115315	NRG CALIFORNIA SOUTH LP, ETIWANDA GEN ST
152707	CPV SENTINEL LLC
169754	OXY USA INC
115389	AES HUNTINGTON BEACH, LLC
7427	OWENS-BROCKWAY GLASS CONTAINER INC
18931	TAMCO
4477	SO CAL EDISON CO
800183	PARAMOUNT PETR CORP
43201	SNOW SUMMIT INC
172005	NEW- INDY ONTARIO, LLC
146536	WALNUT CREEK ENERGY, LLC
800189	DISNEYLAND RESORT
156741	HARBOR COGENERATION CO, LLC
151798	TESORO REFINING AND MARKETING CO, LLC
128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA
11435	PQ CORPORATION
4242	SAN DIEGO GAS & ELECTRIC
115314	LONG BEACH GENERATION, LLC
17953	PACIFIC CLAY PRODUCTS INC
153992	CANYON POWER PLANT
800127	SO CAL GAS CO
800193	LA CITY, DWP VALLEY GENERATING STATION
119907	BERRY PETROLEUM COMPANY
25638	BURBANK CITY, BURBANK WATER & POWER
124838	EXIDE TECHNOLOGIES
51620	WHEELABRATOR NORWALK ENERGY CO INC
5973	SO CAL GAS CO
800168	PASADENA CITY, DWP
3968	TABC, INC
8582	SO CAL GAS CO/PLAYA DEL REY STORAGE FACI
155474	BICENT (CALIFORNIA) MALBURG LLC

800181	CALIFORNIA PORTLAND CEMENT CO
166073	BETA OFFSHORE
114801	SOLVAY USA, INC.
800153	US GOVT, NAVY DEPT LB SHIPYARD
8547	QUEMETCO INC
1073	BORAL ROOFING LLC
700126	GENERAL ELECTRIC COMPANY
129816	INLAND EMPIRE ENERGY CENTER, LLC
127299	WILDFLOWER ENERGY LP/INDIGO GEN., LLC
	INVESTORS

Chapter 6 – Summary of the Proposed Changes in Rule Language and Draft Program Environmental Assessment

Rule 2002 (f)(1) – BARCT Proposed Levels and RTC Reductions

The staff proposal of the new BARCT levels for the refinery and non-refinery sectors are summarized in Table 6 of Rule 2002.

The proposal would result in a programmatic reduction of 14 tons per day RTC holdings over 7 years. Four tons per day would be reduced in 2016 and the remainder would be reduced in equal increments from 2018 to 2022. There would be no reductions proposed for the year 2017. These reductions are reflected in subparagraphs (f)(1)(B) and (f)(1)(C). Subparagraph (f)(1)(B) includes all of the Major Refineries and Investors. The Major Refineries are listed in Table 7 of Rule 2002. Subparagraph (f)(1)(C) includes all other facilities subject to the reduction in NOx RTCs. These facilities are listed in Table 8 of Rule 2002.

The remaining NOx RTCs after a shave for any compliance year would be the Tradable/Usable NOx RTC Adjustment factor in (f)(1)(B) multiplied by the RTC holdings (as of September22, 2015) of all the Major Refineries listed in Table 7 plus the Tradable/Usable NOx RTC Adjustment factor in (f)(1)(C) multiplied by the RTC holdings (as of September 22, 2015) of all the facilities listed in Table 8. Please see Appendix U for further explanation on how the factors in subparagraphs (f)(1)(B) and (C) were derived.

Since the RTC reductions specified in subparagraph (f)(1)(A) have been realized, the conversion of non-tradable/non-usable NOx RTCs to tradable/usable NOx RTCs is no longer applicable to the RTC reductions specified in this subparagraph. The tradable/usable NOx RTCs specified in subparagraph (f)(1)(A) would remain intact and used for calculating RTC reductions for facilities entering the RECLAIM program. However the same approach in converting adjustment factors previously specified in subparagraph (f)(1)(A) would now be applied to the RTC reductions specified in subparagraphs (f)(1)(B) and (f)(1)(C).

Subparagraphs (f)(1)(B) and (f)(1)(C) also include adjustment factors to obtain Non-tradable/Non-usable holdings. The quantity of Non-tradable/Non-usable NOx RTCs is equal to the incremental shave amount in the given compliance year. Subparagraph (f)(1)(G) and (f)(1)(H) specify that shaved RTCs from newer electrical generating facilities listed in Table 9 will be used to fund a Regional NSR Holding Account that can be used, along with their Non-tradable/Non-usable holdings, by these facilities to help meet their ongoing NSR holding requirements.

Subparagraph (f)(1)(I) describes provisions for conversion of Non-tradable/Non-usable holdings to Tradable/Usable NOx RTCs if the 12-month rolling average RTC price exceeds $22,500 per ton. This trigger corresponds to the adopted 2012 AQMP cost effectiveness threshold that triggers additional analysis of proposed rules. Similarly, (f)(1)(I) also requires that the Executive Officer's report to the Board on the trigger price also include a commitment and schedule to conduct a more rigorous cost-effectiveness, market analysis, and socioeconomic impact assessment of the RECLAIM program.

Subparagraph (f)(1)(L) clarifies the method for determining allocations for existing facilities that enter RECLAIM after the date of adoption of the proposed amendments.

Rule 2002 (f)(4) and (f)(5) – Regional NSR Holding Account and State of Emergency Related to Electrical Generating Facilities

A new electrical generating facility, along with all new RECLAIM facilities, must hold sufficient RTCs to offset their entire potential to emit (PTE) for one year prior to commencement of operation and at the beginning of every compliance year thereafter. These requirements are triggered in cases where a facility incurs an emission increase as defined under Rule 2005(d) – Emission Increase. Electrical generating facilities oftenm have PTEs that far exceed their actual emissions, and cannot readily reduce their PTEs given that they must be available for grid support if called upon. Given this burdensome requirement, staff is proposing to create an Regional NSR Holding Account, held by the SCAQMD, that would be used for the purpose of helping such facilities comply with the NSR requirements specified in Rule 2005. These proposed requirements are specified in Rule 2002 paragraph (f)(4). The RTCs in the Regional NSR Holding Account would not be available to offset actual emissions, except for the situation described below.

Staff is proposing in paragraph (f)(5) that during a State of Emergency declared by the Governor related to electricity demand or power grid stability in the Basin, any electrical generating facility can use their Non-tradable/Non-usable NOx RTC holdings to offset their emissions after exhausting their Tradable/Usable holdings. Furthermore, if their Non-tradable/Non-usable NOx RTC holdings are exhausted, they may apply for the use of NOx RTCs in the Regional NSR Holding Account on a quarterly basis. Subparagraphs (f)(4)(i) –(iii) describe the criteria that the Executive Officer must consider in determining the amount and the distribution of these RTCs. If the total RTCs requested exceeds the supply in the Account, the RTCs will be distributed proportionately according to the verified offset needs of the requesting facilities

The RTCs in the Regional NSR Holding Account would be 0.827 tons per day for 2023 & beyond (See Appendix U). These RTCs would be derived from the RTC reductions applied to the newer electrical generating facilities listed in Table 9.

Rule 2002 (i) – RTC Reduction Exemption

Given that no facilities in the history of the RECLAIM program have applied for an exemption pursuant to subdivision (i), and given the unlikelihood that a facility could meet the stringent requirements listed therein, staff is proposing to remove the subdivision in its entirety. .

Rule 2005 – Requirements for New Electrical Generating Facilities

Rule 2005 sets forth requirements for new or modified equipment or processes at RECLAIM facilities. The purpose of the rule is to ensure that the RECLAIM program is equivalent to the federal and state NSR program requirements. One of the requirements is to ensure that the facility must hold sufficient RTCs to offset emission increases for one year prior to commencement of operation and at the beginning of every compliance year thereafter. For an RECLAIM facility existing prior to the adoption of the RECLAIM program, the amendments made in June 3, 2011 required the RECLAIM facility to hold adequate RTCs for the first year of operation prior to commencement of operation of a new or modified source, but will not require the facility to hold RTCs at the commencement of subsequent compliance years, provided that the facility emission level remains below its starting Allocations plus non-tradable credits. However, a new RECLAIM facility will have to continue to hold adequate RTCs equal to the amount of emission increases at the beginning of each compliance year. Any unused RTCs cannot be sold until the end of the compliance year, or the applicable quarters if the facility has permit conditions to cap its emissions during each quarter, thus allowing sale of unused RTCs at the end of the quarter. To remedy this burdensome RTC holding requirement for new electrical generating facilities that cannot change their allowable NOx emissions in their Facility Permit, staff is proposing a Regional NSR Holding Account described in Rules 2002(f)(4) above. Proposed changes in Rule 2005 would assure that the RTCs in the Account would only be used the for the purpose of complying with the NSR requirements (other than access during a power crisis as also described in 2002(f)(4)) . Please see Appendix X for further explanations.

Other Administrative Amendments

Besides the changes described in Rule 2002 and 2005 described above, staff also proposes administrative amendments to Regulation XX to clarify the rule language and to ensure effective and consistent implementation of the RECLAIM program.

Rule 2002(b)(5) - 5-Year Limitation on Amending Annual Emission Reports

Some facilities entering the RECLAIM program have sought to amend their past AERs, which dated as far back as 1989, in ways that increase the initial SOx and/or NOx allocations previously determined pursuant to Rule 2002. The longer the time that has elapsed between the reporting period and the submittal of the amendment, the more problematic the process of validating the proposed changes and the supporting documentation. In fact, such validation has been infeasible in some cases. Therefore, staff is proposing to add language to Rule 2002(b)(5) to provide clarity on which annual report submittals and/or revisions may be considered by staff in determining facility allocations.

Rules 2011 and 2012 - Delayed RATA Tests due to Extenuating Circumstances

Rules 2011 and 2012 set forth monitoring, reporting, and recordkeeping requirements for sources of SOx and NOx at RECLAIM facilities. The accompanying Appendices A to these rules outline in greater detail the technical specifications required for monitoring, reporting, and recordkeeping for RECLAIM sources such as the timing and frequency of Semi-Annual Assessments in the form of Relative Accuracy Test Audits (RATAs) for CEMS. RATAs must be conducted while the equipment is in operation. Equipment monitored by CEMS at some RECLAIM facilities, however, may experience extenuating circumstances that prevent them from conducting RATA tests in a timely manner.

Additionally, facilities under contract with the California Independent System Operator (CalISO), as well as electrical generating facilities owned and operated by municipalities, have experienced difficulties in meeting RATA deadlines because their equipment operates based on current energy demand and may not operate long enough (or at all) to conduct a RATA in the quarter in which RATA is due. Electrical generating facilities with equipment under contract with CalISO or owned and operated by municipalities often do not know when demand for electricity will result in generation equipment being required to operate until a day prior, creating scheduling difficulties in conducting RATAs and precluding the use of non-operational status. The inherent inconsistent operational nature of such equipment at electric generating facilities sometimes causes a need to postpone their RATAs.

Under current rule requirements, facilities having such extenuating circumstances seek variances for indeterminate amounts of time. The proposed amendments would, under specific conditions and criteria, allow RECLAIM Facility Permit Holders of equipment experiencing these extenuating circumstances to postpone RATAs. The specific conditions and criteria are further explained in details in Appendix X.

Rules 2011 and 2012 - Typographical Edits

Staff also proposes to make several typographical clarifications and corrections in Rules 2011 and 2012 Appendix A, Attachment C B.2.b and Rule 2011 Appendix A, Attachment C B.2.e. Please see Appendix X for further explanations.

Draft Program Environmental Assessment (PEA)

A Notice of Preparation/Initial Study (NOP/IS) was released for a 57-day public review and comment period from December 5, 2014 to January 30, 2015. Eight comment letters were received from the public regarding the preliminary analysis in the NOP/IS. These comment letters and responses to individual comments are included in Appendix G of the Draft Program Environmental Assessment (PEA). In addition, on January 8, 2015, a CEQA and Socioeconomic Scoping Meeting was held. CEQA comments raised at the Scoping Meeting have been summarized and responded to in Appendix H of the Draft PEA. Socioeconomic comments raised at the Scoping Meeting and in the two comment letters specific to socioeconomic issues received are addressed in the Draft Socioeconomic Analysis. The Draft PEA was released on August 13, 2015, and the commenting period was extended until October 6, 2015. The Draft Socioeconomic Analysis was released on September 9, 2015.

Draft Findings under California Health and Safety Code

California Health and Safety Code § 40727 requires that prior to adopting, amending or repealing a rule or regulation, the 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

A need exists to amend Rules 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx), 2005 – New Source Review for RECLAIM, 2011 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions (Protocol), and 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions (Protocol) to seek additional emission reductions from RECLAIM relative to the 2012 AQMP (Control Measure CMB-01), to demonstrate BARCT equivalence pursuant to California Health and Safety Code §40440, and to make changes necessary for the ongoing administration of the program.

Authority

The AQMD Governing Board has authority to amend existing 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx), 2005 – New Source Review for RECLAIM, 2011 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions (Protocol), and 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions (Protocol), pursuant to California Health and Safety Code §§ 39002, 40000, 40001, 40440, 40440.1, and 40702.

Clarity

The proposed amended rules are written or displayed so that their meaning can be easily understood by the persons directly affected by them.

Consistency

The proposed amended rules are in harmony with and not in conflict with or contradictory to, existing statutes, court decisions or state or federal regulations.

Non-Duplication

The proposed amended rules will not impose the same requirements as any existing state or federal regulations. The amendments are necessary and proper to execute the powers and duties granted to, and imposed upon, AQMD.

Reference

By adopting the proposed amended rules, the AQMD Governing Board will be implementing, interpreting and making specific the provisions of the California Health and Safety Code §§ 39002, 40001, 40440 (a), 40440.1, 40702, and 40725 through 40728.5; and Title 42 U. S. C. Sections 7410 and 7511a.

Comparative Analysis

H&S Code §§ 40727 and 40727.2 require a written analysis comparing the proposed amended rule with existing regulations. The §40727.2 analysis is traditionally applied to source-specific rules requirements affecting equipment subject to a command-and-control regulatory approach. RECLAIM varies from this regulatory approach in that it is based on a mass cap approach with a declining balance. This regulatory program decreases emission credit holdings, which caps emissions at a facility, as opposed to application of equipment-specific requirements. Therefore, this comparative analysis differs from the traditional comparative analysis. A comparative analysis for the RECLAIM program was provided for Rule 2002, amended on January 7, 2005 (NOx RECLAIM sources) and November 5, 2010 (SOx RECLAIM sources).

A comparative analysis, as required by H&S Code §40727.2, compares individual pieces of equipment to any applicable standard. The key to this analysis is to demonstrate non-duplication of new or amended regulatory requirements on an affected source. The current proposed RECLAIM amendment primarily seeks to reduce RTCs in the market and NOx emissions. There are no significant changes proposed to the other program elements, such as enforceable procedures, operating parameters or work practice requirements. In addition, amendments to the monitoring, recordkeeping, and reporting requirements are administrative in nature, as they do not affect or otherwise change an emissions limitation or add a significant requirement. On this basis, this comparative analysis focuses only on the determination of a new BARCT standard for the equipment under RECLAIM.

Relative to the derivation of new BARCT standards, all of the equipment categories listed in Tables 1 and 3 of Rule 2002 were examined by staff and presented to stakeholders for comments and feedback. However, as shown in Table 3.1 of this staff report, new BARCT was only determined for fluid catalytic cracking units, refinery boilers and heaters greater than 40 million British thermal units per hour (mmbtu/hr), refinery gas turbines, coke calciner, sulfur recovery units/tail gas incinerators, cement kilns, container glass melting furnaces, sodium silicate furnace, heat treating furnaces greater than 150 mmbtu/hr, non-refinery gas turbines, and internal combustion engines. In making the BARCT determinations, as discussed in Appendices A through S, a systematic approach of analysis was undertaken to derive any new control standards. This analysis included review of potentially applicable requirements from other air pollution control districts or agencies, applicable AQMD rules, as well as emission controls achieved in practice or otherwise technologically and economically feasible that would have otherwise been required under a command-and-control regulatory approach in the absence of RECLAIM. The results of the BARCT analysis are presented by equipment category in Appendices A through S.

The proposed programmatic reductions are based on the determination of new BARCT for certain emission sources. The resulting equipment-level reductions that would have occurred if applied with the same percentage under a command-and-control regulatory program are subsumed and spread among the RECLAIM facilities which hold 90 percent of the RECLAIM Trading Credits (RTC). The RTCs are proposed to be reduced at a rate of 66 percent for the larger refineries and investors and 49 percent among the remaining facilities that comprise those facilities holding 90 percent of the RTCs. As RECLAIM is a market-based program with facility-level mass emissions caps there are no specific air pollution control requirements (i.e., equipment specific emission limits) for these sources that must be met by these RECLAIM facilities holding 90 percent of the RTCs. Facilities are allowed the flexibility to meet their reduction requirements by whatever means they choose, such as equipment modifications, installation of control equipment, or purchasing RTCs.

Notwithstanding the aforementioned discussion, RECLAIM facilities are subject to the requirements of other AQMD regulations not subsumed by the program, including requirements under Regulation II – Permits, and Regulation IV – Prohibitions, such as Rule 401 – Visible Emissions, Rule 402 – Nuisances, and Rule 403 – Fugitive Dust. It should be noted that there are federally mandated programs, such as New Source Review (BACT/LAER), Prevention of Significant Deterioration, and Standards of Performance for New Stationary Sources, which are also applicable to the RECLAIM program and incorporated within the program. RECLAIM also complies with federal policy regarding start-up, shutdown, and malfunctions. In addition, there is not a comparable state or federal program for a cap and declining balance of NOx emissions. However, RECLAIM, as it currently exists, is in the SIP and complies with federal requirements applicable to market-type air pollution control programs, such as the Economic Incentive Program (EIP) guidelines.

Consequently, RECLAIM stands on-its-own and does not contain any duplicative or conflicting regulatory requirements.

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 that would achieve the emission reduction objective of the proposed amendments, relative to NOx. The proposed control option is what was analyzed in the BARCT analysis, while the alternative control option is BARCT control to a less stringent level.

To determine the incremental cost effectiveness, the calculated difference in the dollar cost between the two control options is divided by the difference in their emission reduction potentials.

The control costs for the staff proposal used the average cumulative present worth values for each source category. The control costs for the alternative project used the same costs for the control equipment because it is assumed that a majority of the same costs to build and construct a control system despite a higher emission level would still apply.

The emission reductions of the alternative project are calculated by using the higher BARCT level applied to each source category. The emission reductions of the proposed control option are also factored into the final calculation.

The difference of the PWV of the alternative control option and the proposed control option (the PWV is the same in this case) is divided by the difference in the emission reduction potentials for both projects. If "a" is the alternative control option and "p" is the proposed control option, then the incremental cost effectiveness is:

$$(C_a - C_p) / (E_a - E_p) = \$ \text{ costs /per ton}$$

When calculated across all the source categories subject to BARCT for NOx RECLAIM, the incremental cost effectiveness for the source categories ranged from $53,000/ton to $917,000/ton. The table below lists the incremental cost effectiveness values calculated for all the source categories subject to the BARCT analysis.

Source Category	**Incremental Cost Effectiveness ($/ton)**
FCCUs	$117,000
Refinery Gas Turbines	$60,000
Boilers/Heaters >40 MMBTU/hr	$61,000
Coke Calciner	$897,000
SRU/TG Incinerators	$63,000
Container Glass Melting Furnaces	$78,000
Sodium Silicate Furnace	$122,000
Metal Heat Treating Furnace >150 MMBTU/hr	$61,000
Non-Refinery, Non-Electrical Generating Facility Gas Turbines	$917,000
Non-Refinery, Non-Electrical Generating Facility IC Engines	$53,000

The calculated values clearly indicate that the alternative control option is not viable when compared to the proposed controls.

Part I – BARCT Analyses for Refinery Sector

Part I contains the information related to the BARCT analyses for the refinery sector. Part I includes 10 Appendices from Appendix A to Appendix J that discuss 1) the NOx control technologies, 2) costs and cost effectiveness analyses for major NOx sources at the refineries, and 3) the consultant's analyses. The NOx reductions co-benefits of the energy efficiency projects at the refineries are summarized in Appendix K. The Survey Questionnaires sent to the refineries in 2003 to collect pertinent information for this BARCT analyses are included in Appendix L.

Appendix A - Refinery Fluid Catalytic Cracking Units

Process Description

There are five refineries that operate six fluid catalytic cracking units (FCCU) in the SCAQMD: Chevron, ExxonMobil, Tesoro (Carson and Wilmington), Phillips66, and Valero. The FCCUs are classified as major sources of emissions in RECLAIM, and as such, the NOx emissions from FCCUs are required to be monitored with a continuous emission monitoring system (CEMS), and reported on a daily basis electronically to the SCAQMD. A brief description of the process is presented below.

An FCCU converts heavy oils into more valuable gasoline and lighter products. A schematic of the process is shown in Figure A.1. The process uses a very fine catalyst that behaves as a fluid when aerated with a vapor. The fluidized catalyst is circulated continuously between a reactor and a regenerator and acts as a vehicle to transfer heat from the regenerator to the oil feed in the reactor. The cracking reaction is endothermic and the regeneration reaction is exothermic. The fresh feed is preheated by heat exchangers to a temperature of 500-800 degrees Fahrenheit and enters the FCCU at the base of the feed riser where it is mixed with the hot regenerated catalyst. The heat from the catalyst vaporizes the feed and raises it to the desired reaction temperature. The mixture of catalyst and hydrocarbon vapor travels up the riser into the reactor. The cracking reaction starts in the feed riser and continues in the reactor. Average reactor temperatures are in the range of 900-1,000 degrees Fahrenheit. As the cracking reaction progresses, the catalyst surface is gradually coated with carbon (coke), reducing its efficiency. While the cracked hydrocarbon vapors are routed overhead to a distillation column for separation into lighter components, the oil remaining on the catalyst is removed by steam stripping before the spent catalyst is cycled to the regenerator.

In the regenerator, spent catalyst is reactivated (regenerated) by burning the coke off the catalyst surface. The regenerated catalyst is generally steam-stripped to remove adsorbed oxygen before being cycled back to the reactor. The regenerator exit temperatures for catalyst are about 1,200-1,450 degrees Fahrenheit. The regenerator can be designed and operated to either partially burn the coke on the catalyst to a mixture of carbon monoxide (CO) and carbon dioxide (CO_2), or completely burn the coke to CO_2. The regenerator temperature is carefully controlled to prevent catalyst deactivation by overheating and to provide the desired amount of carbon burn-off. This is done by controlling the air flow to give a desired CO_2/CO ratio in the exit flue gases or the desired temperature in the regenerator. The flue gas containing a high level of CO is routed to a supplemental-fuel fired CO boiler if needed to completely burn off the CO to CO_2. The FCCUs in the SCAQMD are currently operated in a completely burn mode; what used to be the CO boilers are used as heat recovery devices without any supplemental fuel.

It is during the regeneration cycle that some of the catalyst is lost in the form of catalyst fines, and NOx, SOx and other pollutants are formed. The FCCU is a major source of sulfur oxides (SOx), nitrogen oxides (NOx), particulate matter (PM10, PM2.5), as well as ammonia (NH3), hydrogen cyanide (HCN) and other pollutants in the refinery. Approximately 90% of the NOx generated from the FCCUs are from the nitrogen in the feed that is accumulated in the coke which is then burned-off in the regenerator. This portion of the NOx is called "fuel" NOx. "Fuel" NOx is a combination of nitric oxide (NO), nitrogen dioxide (NO_2), and nitrous oxide (N_2O). The remaining 10% of the NOx generated from the FCCUs are "thermal" NOx which is generated in the high temperature zones in the regenerator, and "prompt" NOx generated from the reaction between nitrogen and oxygen in the combustion air. The NOx emissions from the FCCU are typically controlled with selective catalytic reduction (SCR), LoTOx scrubbers, and/or NOx reducing additives.

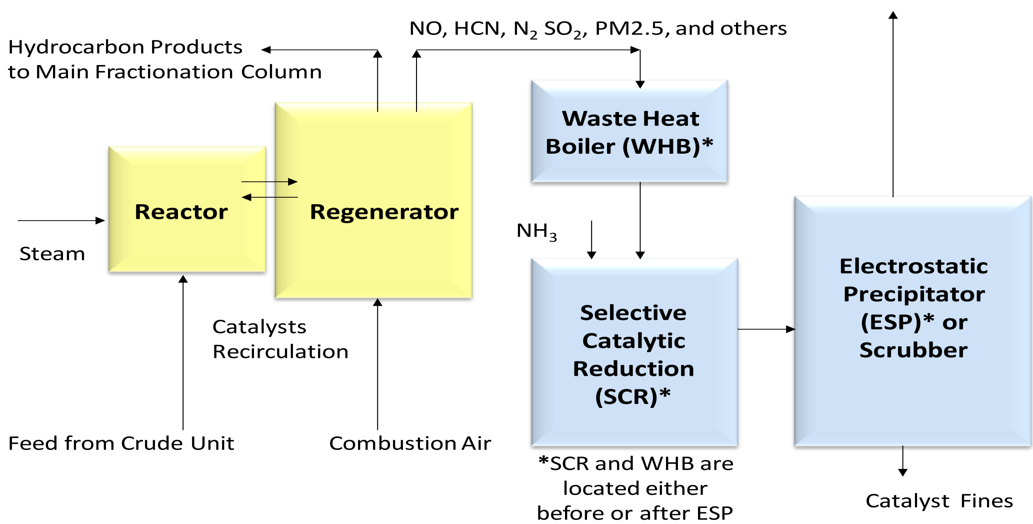


Figure A. 1 - Simplified Schematic of FCCU Process

Emission Inventory

As shown in Table A.1, the total 2011 NOx emissions from the six FCCUs (two with downstream CO boilers/heat exchangers) located in the SCAQMD are 1.08 tons per day.

Three FCCUs at Refinery 6, 1 and 5 use SCRs installed in 2000, 2003 and 2008, respectively to control NOx emissions. Three FCCUs at Refinery 4, 7 and 9 have no NOx controls.

As shown in Table A.1, Refinery 1's FCCU with SCR currently emits at a level under 2 ppmv NOx (with a 5 ppmv ammonia slip.) The NOx concentrations from other FCCU/CO units vary from 6 to 45 ppmv. Figure A.2 graphically shows the 2011 NOx emissions and the regenerator exhaust gas NOx concentrations for the six FCCUs in the SCAQMD. Comparing the data of the six FCCUs, Refinery 1's FCCU operating with SCR installed in 2003 has the lowest NOx emissions and the lowest NOx concentrations at below 2 ppmv.

As previously mentioned, 90% of the NOx emissions from the FCCUs are generated from the nitrogen in the FCCU feed (or coke in the regenerator.) Figure A.3 shows the NOx emissions compared to the FCCU feed rates. Comparing the data of the six FCCUs, Refinery 1 has the highest feed rate but achieves the lowest emissions with the use of an SCR.

Table A. 1 - 2011 Emissions for Refinery FCCUs

Facility ID	Device ID	Device	Process/NOx Control	2011 Emissions (lbs)	Current NOx ppmv @ 3% O2
5	203	REGEN1	FCCU/SCR	119,724	14.84
1	164	REGEN2	FCCU/SCR	16,686	1.21
6	151	REGEN3	FCCU/SCR	123,008	5.62
6	164	CO BOILER	FCCU/SCR	20,038	5.62
4	112	CO BOILER	FCCU/no control	157,150	21.0 - 27.6
4	96	REGEN4	FCCU/no control	in CO Boiler	21.00
7	1	REGEN5	FCCU/no control	101,648	12.88
9	36	REGEN6	FCCU/no control	249,277	35.5 - 45
			Total	**1.08 tons per day**	

Achieved-In-Practice Level for FCCU

Refinery 1 FCCU's SCR has demonstrated that a level of 2 ppmv NOx at 5 ppmv ammonia slip is achieved in practice. [Reference 1]

- The SCR was installed and operated since 2003. It was designed with a NOx inlet of 155 ppmv to achieve a level of 10 ppmv NOx outlet concentration (>90% control efficiency)

- At normal operations, the inlet NOx concentrations range from 40 - 80 ppmv, and the outlet NOx concentrations are typically below 2 ppmv with 5 ppmv ammonia slip (95% - 98% control efficiency). The SCR is capable of having three catalyst layers, each 29 ft x 29 ft x 4.5 ft deep; and is operated with two layers to reach 95% - 98% control. Catalyst life is 5 to 6 years.

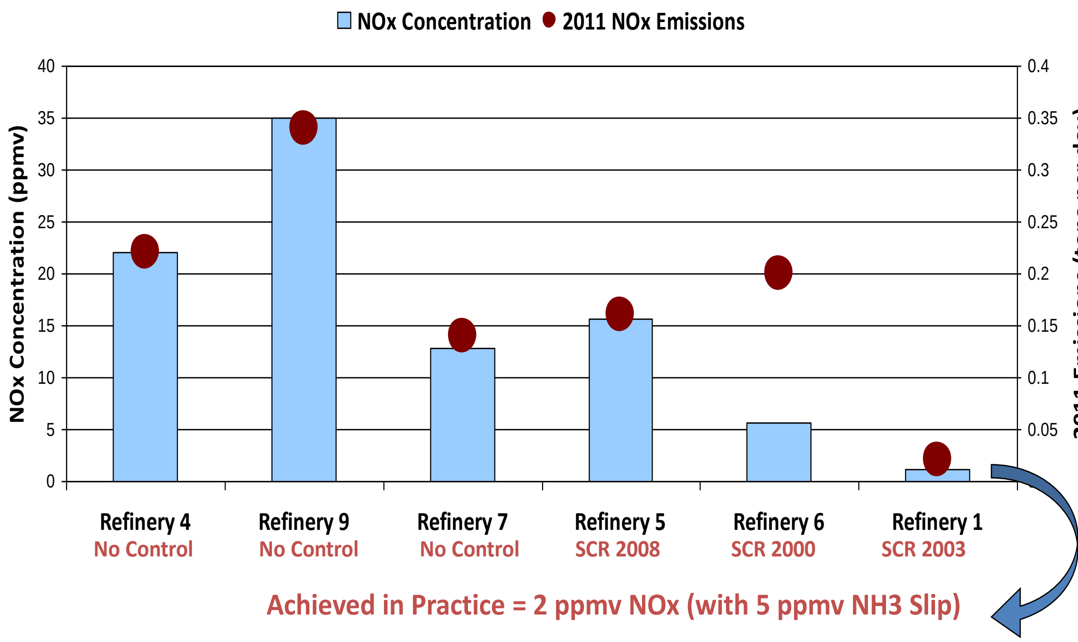


Figure A. 2 - 2011 NOx Emissions and NOx Concentrations for Refinery FCCUs

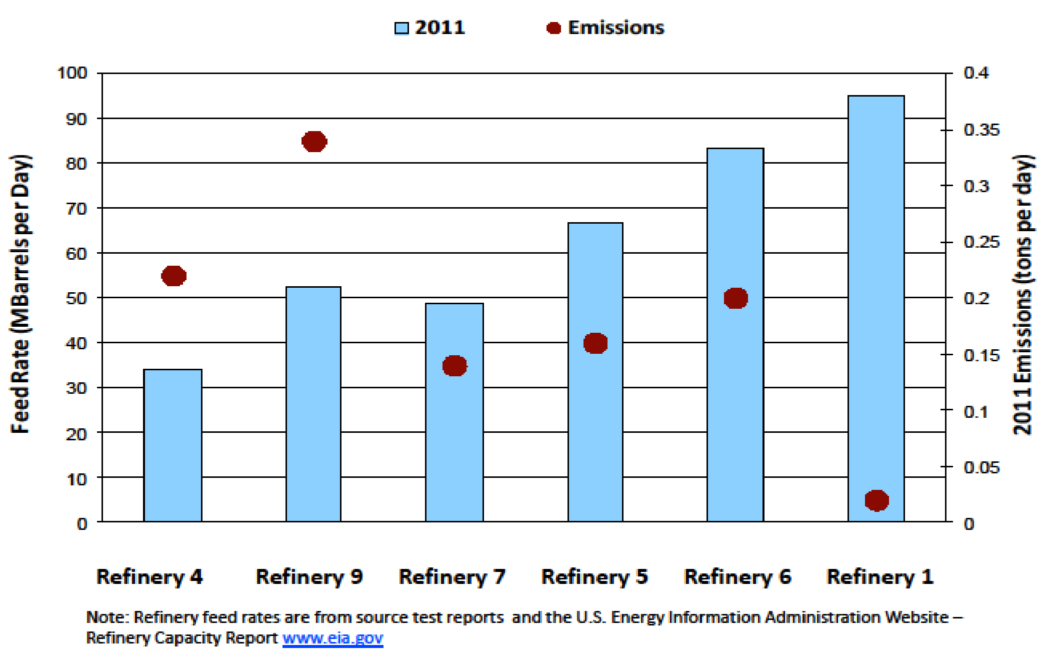


Figure A. 3 - 2011 NOx Emissions and Feed Rates for Refinery FCCUs

Control Technology

The commercially available control technologies for NOx are discussed below.

Selective Catalytic Reduction (SCR)

For the past two decades, SCR technology has been used successfully to control NOx emissions. The technology is considered mature and commercially available. SCRs can be designed to reduce 95%-98% NOx emissions from the FCCUs and achieve 2 ppmv NOx while maintaining a low ammonia slip of less than 5 ppmv. [1-17]

SCR is an effective control technology for NOx which uses ammonia (NH_3) to selectively reduce NOx to nitrogen through the following reactions: [2 - 4]

$$4\ NH_3 + 4\ NO \rightarrow 4\ N_2 + 6\ H_2O \qquad \text{(Reaction 1)}$$
$$4\ NH_3 + 2\ NO + 2\ NO_2 \rightarrow 4\ N_2 + 6\ H_2O \qquad \text{(Reaction 2)}$$

It should be noted that, at temperatures above 797 ^oF, ammonia can be oxidized to form NO and N_2O. These are undesirable reactions since NO and N_2O will ultimately convert to NOx and increase the NOx emissions. [5]

$$4\ NH_3 + 5\ O_2 \rightarrow 4\ NO + 6\ H_2O \qquad \text{(Reaction 3)}$$
$$4\ NH_3 + 4\ NO + 3\ O_2 \rightarrow 4\ N_2O + 6\ H_2O \qquad \text{(Reaction 4)}$$

A successful SCR catalyst can facilitate the reduction of NH_3 (Reaction 1 and 2) while subsiding the NH_3 oxidation reactions (Reaction 3 and 4). Typically, the SCR catalysts are vanadium, titanium, and/or zeolite based with different sizes and shapes, and have various ranges of operating temperatures: [5 – 8, 18]

Conventional SCR catalysts:	400 degrees F - 800 degrees F
Low temperature SCR catalysts:	300 degrees F - 400 degrees F
High temperature SCR catalysts:	800 degrees F - 1100 degrees F

The stochiometric amount of ammonia required is 1 mole of NH_3 per mole of NOx reduced (NH_3/NOx = 1). Ammonia injection and mixing are critical since a non-uniform distribution and mixing of ammonia can result in inadequate NOx conversion and extensive ammonia slip.

To reduce the ammonia slip caused by imperfect ammonia distribution and mixing, SCR manufacturers have developed the Ammonia Slip Catalyst (ASC), a layer of catalyst which can be installed downstream of the SCR catalyst. Early generation of ASCs were based on precious metal which is highly active for NH_3 oxidation. The current newly developed ASCs selectively favor the NH_3 reduction over the NH_3 oxidation: NH_3 is partially oxidized to NO (Reaction 3) and NO is then quickly reduced to N_2 (Reaction 1 and 2). In addition, the advanced ACSs highly support the oxidation of CO to CO_2. Other advantages of ASCs are summarized below: [5, 9-10]

- Enhancing the selective reduction of NO to N2 and supporting the oxidation of CO to CO2 while suppressing the oxidation of NH3 to NOx;
- Allowing for operations at higher NH_3/NOx ratios to ensure complete NOx conversion;
- Maintaining low ammonia slips; and
- Reducing the overall SCR catalyst volume while maintaining the high NOx control efficiency.

In the SCAQMD, aqueous ammonia is required to be used with SCRs instead of anhydrous ammonia due to safety reasons. In general, aqueous ammonia has lower risks and higher operating costs than anhydrous ammonia. A larger volume of aqueous ammonia will be required to achieve the same NOx reduction, thus increasing the costs of deliveries (e.g. for 29% aqueous ammonia, the delivery costs is in transporting 71% water with the ammonia.) Aqueous ammonia requires either compressed air for atomization or vaporizers to evaporate the water. The costs for operating with aqueous ammonia are approximately two times higher than the costs for operating with anhydrous ammonia. [11-13]

Sulfur dioxide (SO_2) to sulfur trioxide (SO_3) conversion and ammonium bisulfate (ABS) formation are undesirable reactions in the SCR process. SO_3 and ABS can cause plugging at downstream components. However, the main factors affecting the formation of ABS, such as temperature, the amount of ammonia slip, molar ratio of ammonia to NOx, the SO_3 concentrations, and fly ash contents; and the methods to control SO_3 ABS formation to reduce its negative effects have been well investigated, documented, and implemented by the SCR manufacturers as well as the SCR users. In addition, ABS is unlikely to be a problem for low flue gas sulfur units. [14]

LoTOx™ Application with Scrubber

LoTOx™ stands for “Low Temperature Oxidation” process in which ozone is used to oxidize insoluble NOx compounds to soluble NOx compounds. These soluble compounds can then be removed by absorption in caustic solution, lime or limestone. The LoTOx™ process is a low temperature operating system, optimally operating in a range of 140 - 325 degrees F. The LoTOx™ is a registered trademark of Linde LLC. (previously BOC Gases) and was later licensed to BELCO of Dupont for refinery applications. The LoTOx application is explained below. [19 - 27]

A typical combustion process produces about 95% NO and 5% NO_2. Both NO and NO_2 are relatively insoluble in aqueous solution, and thus a wet gas scrubber is not efficient in removing these insoluble compounds from the flue gas stream. However, with the introduction of ozone, NO and NO_2 can be easily oxidized to highly soluble compounds N_2O_5 (Reaction 5 and 6) and subsequently converted to nitric acid HNO_3 (Reaction 7). The nitric acid is then rapidly absorbed in caustic solution (Reaction 8), limestone or lime (Reaction 9 and 10), and removed from the wet scrubbers. In addition, the rates of oxidizing reactions for NOx (Reaction 5 and 6) are fast compared to SO_2 oxidation reaction (Reaction 11), and as a result, there is no ABS or SO_3 formation. The LoTOx process can be integrated with any types of wet scrubbers (e.g. venturi, packed beds), semi-dry scrubbers, or wet electrostatic precipitators (ESPs).

$NO + O_3 \rightarrow NO_2 + O_2$ (Reaction 5 - Fast)

$2\ NO_2 + O_3 \rightarrow N_2O_5 + O_2$ (Reaction 6 – Fast)

$N_2O_5 + H_2O \rightarrow 2\ HNO_3$ (Reaction 7)

$HNO_3 + NaOH \rightarrow NaNO_3 + H_2O$ (Reaction 8)

$2HNO3 + CaCO3 \rightarrow Ca(NO_3)_2 + H_2O + CO_2$ (Reaction 9)

$2HNO3 + Ca(OH) \rightarrow Ca(NO_3)_2 + 2H_2O$ (Reaction 10)

$SO_2 + O_3 \rightarrow SO_3 + O_2$ (Reaction 11 - Very slow)

The LoTOx process requires oxygen supply and ozone generation. Oxygen is used to generate ozone on site. Typically oxygen is stored as liquid in vacuum jacketed vessels or is delivered by pipeline. Ozone is an unstable gas and it is typically generated on demand using an ozone generator. An ozone generator is shaped similar to a shell and tube heat exchanger. A corona discharge is used to dissociate oxygen into individual atoms; and the oxygen atoms combine with other oxygen molecules to form ozone. An ozone injection manifold should be designed to achieve uniform distribution and complete mixing. A ratio of NOx/O_3 of about 1.75 – 2.5 is needed to achieve 90% to 95% NOx conversion and reduction. Since sulfites are ozone scavengers, the LoTOx process typically has a very low ozone slip of 0-3 ppmv.

Several advantages of LoTOx application in comparison to SCR are:

— LoTOx is a low temperature operating system, meaning that it does not require heat input to maintain operational efficiency and enables maximum heat recovery of high temperature combustion gases.

— LoTOx can be an integrally connected to a wet (or semi-wet) scrubber, and become a multi-component air pollution control system that can reduce NOx, SOx and PM in one system whereas SCR is primarily designed to reduce only NOx

— There is no ammonia slip, SO_3, and ABS issues associated with LoTOx application.

BOC Gases received a grant funded partially by the California Air Resources Board to demonstrate the LoTOx technology at a reverbertory furnace used for lead smelting, operated by Quemetco Inc., City of Industry in California. The demonstration was successful, accomplishing > 90 percent NOx removal which led to a full scale system installation in 2001.[23] Today, there are more than 50 applications engineered by Linde since 1997,[19] and more than two dozen applications with EDV™ scrubbers engineered by BELCO since 2007.[26] EDV™ is a registered trademark of BELCO. LoTOx with EDV™ scrubber is shown in Figure A.4.

Table A.2 contains a list of the LoTOx applications for FCCUs, boilers, furnaces, and other combustion equipment. This is not an inclusive list. Applications in gas-fired and high sulfur coal-fired units met 95% control (2 ppmv - 5 ppmv). Current installations in refineries have achieved NOx level of 8 ppmv -10 ppmv (85% - 95% control efficiency). Manufacturers have confirmed that LoTOx can be designed to achieve 2 ppmv NOx from current inlet concentrations (85%-95% control efficiency) for FCCUs.

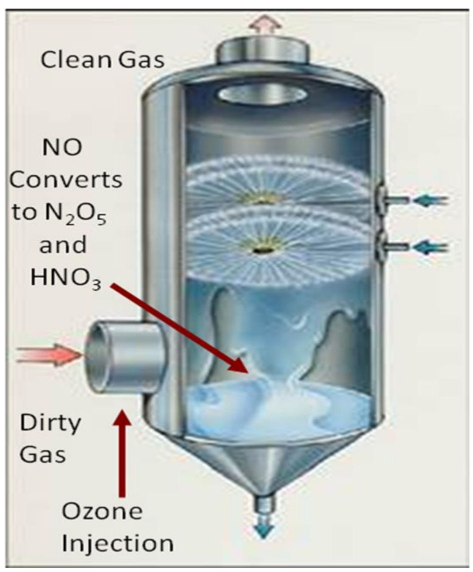


Figure A. 4 - EDV Scrubber with LoTOx Application

Table A. 2 – List of LoTOx Applications

No	Application	Exhaust Gas Flow (scfm)	NOx Inlet (ppmv)	NOx Outlet (ppmv)	% Control	Startup Date
1	400 HP natural gas fired boiler *	4,000	30-70	2	97%	1997-98
2	Stainless steel pickling	4,000	3400	100	97%	2000
3	25 MW coal fired boilers	90,000	200	10-20	95%	2001
4	Lead recovery furnace	26,000	50-150	10	93%	2002
5	1000 HP natural gas fired boiler *	10,000	20-40	4	90%	2001
6-10	Five (5) FCCUs in the U.S.	40,000-260,000	70-120	8-20	80%	2007
11-12	Sulfuric acid plants in the U.S.	2 x 16,800	90	10	90%	2008
13-23	Nine (9) FCCUs and 2 LoTOx ready installations in the U.S.	12,000 – 310,000	30-250	10-18.5	93%	2008-15
24-40	Ten (10) FCCUs, a refinery boiler, 6 LoTOx ready installations in China	90,000-390,000	100-350	20-73	80%	2012-15
41-42	FCCUs in Thailand & Romania	43,000-135,000	230-250	20-73	80%	2015-19

Note: See Reference 19. * Units are in Southern California.

NOx Reduction Additives

The combustion in the FCCU regenerator generates a dozen of various pollutants (NO, N_2O, NO_2, HCN, NH_3, CO, SO_2 etc) and the dynamic interaction of these compounds with each other is complex. A simplified version of the chemical reactions in the FCCU regenerator is shown in Figure A.5. “Fuel” nitrogen in the coke is first converted to HCN. HCN is thermodynamically unstable and it is converted to NH_3, N_2, NO, N2O, NO_2 compounds. The rates of these reactions depend heavily on the regenerator temperatures and the regenerator configuration. NOx reduction additives can be used to promote the conversion of NOx, HCN, and NH_3 to N_2 and reduce NOx emissions. The removal efficiency for NOx Reduction Additives is reported to vary from 50% to 80%. [28-38]

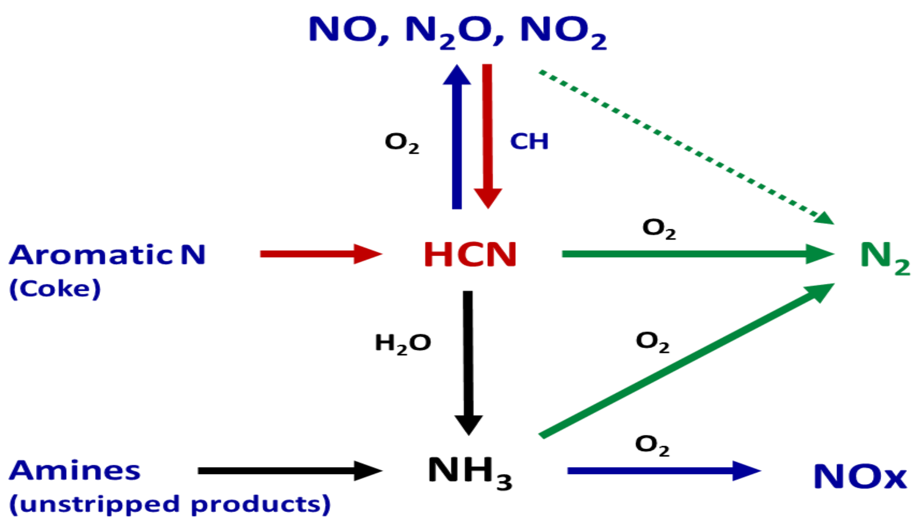
No	Application	Capacity (bpsd)	NOx Inlet (ppmv)	NOx Outlet (ppmv)	% Control	Startup Date
1	FCCU, Arkansas	20,000	70-100	10	86%	2007
2	FCCU, Texas City, TX	130,000	100-200	10	95%	2007
3	FCCU, Texas City, TX, retrofit	60,000	100-150	8	95%	2007
4	FCCU, Texas City, TX, retrofit	52,000	70-100	10	90%	2007
5	FCCU, Houston, TX, retrofit	58,000	100-150	10	93%	2007
7	FCCU, St. Charles, LA, retrofit	100,000	Confidential			2010
8	FCCU, Corpus Christi, TX, retrofit	45,000				2010
9	FCCU, Delaware, DE, retrofit	75,000				TBD
10	FCCU, El Dorado, KS	40,000	150	20	86%	TBD
11	FCCU, Ardmore, Oklahoma	40,000	TBD			TBD
12	FCCU, Three Rivers, Texas	28,000				TBD
13	FCCU, Placid Refining, LA	30,000				TBD

Note: Refer to Reference 20 for additional installations inside and outside of the U.S. Some scrubbers have built in ready for LoTOx retrofit but ozone generators have not yet been installed as of May 2013.

Manufacturers of the NOx reduction additives such as BASF, INTERCAT and Grace Davidson recommended the following best practices to minimize the NOx formation with the use of their additives, and at the same time, promote the conversion of CO to CO2:

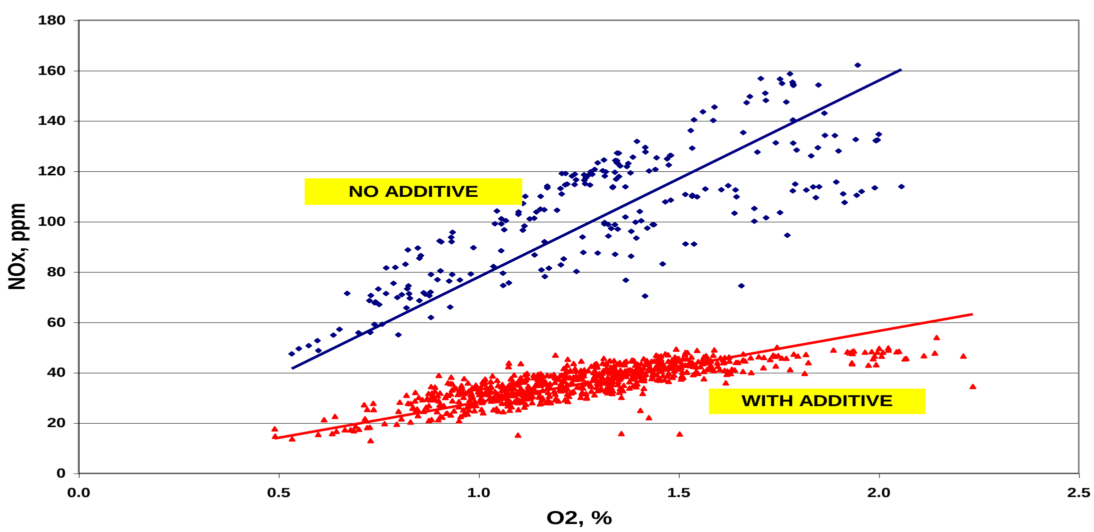
- Minimizing excess oxygen,
- Reducing feed nitrogen, and
- Utilizing non-platinum CO promoters

Figure A.6 shows outlet NOx concentrations of a FCCU with and without the use of NOx Reduction Additives. Data in Figure A.6 shows that higher excess oxygen favors the formation of NOx rather than N_2, and NOx Reducing Additives are capable of removing 60% of NOx emissions. NOx Reduction Additives cannot yet reduce NOx to 2 ppmv levels, however additives may be used in combination with other control technologies to reach the targeted levels. Two manufacturers indicated that NOx additives generally would cost about $15-$20 per pound and would be used at a rate between 1-3% of the FCC fresh catalyst addition rate. The NOx control effectiveness of the NOx Reducing Additives would be very specific for each FCCU application.



(Picture taken from References 22 and 23)

Figure A. 5 - Nitrogen Chemistry in the FCC Regenerator



(Picture taken from Reference 22)

Figure A. 6 - NOx Reduction Additive Reduces NOx Emissions by 60%

Costs and Cost Effectiveness for SCRs

Several methodologies were used to estimate the costs and ensuing cost effectiveness of installing or modifying the SCR's for the FCCU controls to 2 ppmv NOx. These included direct cost estimates from refiners, scaling cost estimates based on flue gas flow rates, using U.S. EPA's guideline approach, an upper range industry cost factor and a consultant's independent assessment.

Refinery 1

The refinery 1 SCR achieved 2 ppmv NOx and 5 ppmv NH3 slip. Refinery 1 provided staff with the total installed costs, ammonia costs, and catalysts replacement costs for their SCR. [1] Staff estimated Present Worth Value (PWV) for Refinery 1 SCR using the equations below assuming 4% interest rate and 25-years SCR life. The PWV of Refinery 1 SCR was estimated to be $41 million dollars.

$$PWV_{Ref\ 1} = TIC_{Ref\ 1} + (15.62 \times AC_{Ref\ 1}) + (2.52 \times CR_{Ref\ 1}) \qquad \text{(Equation 1)}$$

Where:

$PWV_{Ref\ 1}$ = Present Worth Value, $
$TIC_{Ref\ 1}$ = Total Installed Costs, $
$AC_{Ref\ 1}$ = Annual Operating Costs, $
$CR_{Ref\ 1}$ = Catalysts Replacement Costs, $

Refinery 5, 6 and 7

Costs for the SCRs at Refineries 5, 6 and 7 were derived based on Refinery 1's data. The PWV of Refinery 5, 6, and 7 SCRs were estimated using the PWV of Refinery 1 SCR and the ratios of their appropriate inlet flue gas flow rates to the 0.7 power as follows. The PWVs of SCRs for Refinery 5, 6 and 7 were estimated to be $33 million, $57 million and $27 million respectively as shown in Table A.3.

$$PWV_{Ref\ 5} = PWV_{Ref\ 1} \times (\text{Flow Rate}_{Ref\ 5} / \text{Flow Rate}_{Ref\ 1})^{\wedge 0.7} \qquad \text{(Equation 2)}$$
$$PWV_{Ref\ 6} = PWV_{Ref\ 1} \times (\text{Flow Rate}_{Ref\ 6} / \text{Flow Rate}_{Ref\ 1})^{\wedge 0.7}$$
$$PWV_{Ref\ 7} = PWV_{Ref\ 1} \times (\text{Flow Rate}_{Ref\ 7} / \text{Flow Rate}_{Ref\ 1})^{\wedge 0.7}$$

Refineries 5 and 6 installed their SCRs in 2008 and 2000 respectively. In order to meet the 2 ppmv NOx proposed level, they may choose to 1) retrofit their existing SCRs, or 2) add additional catalysts to their existing SCRs if space is available (Note: Refinery 1 only utilizes 2 layers out of 3 layers of catalysts to meet 95% - 98% control), or 3) change the existing catalysts to a more effective catalyst type. As shown in Table A.3, the PWVs in these scenarios can be potentially less than $33 million and $57 million dollars for Refineries 5 and 6, respectively.

Refinery 4 and 9

Refinery 4 and Refinery 9 FCCUs have no controls for NOx emissions. Several manufacturers provided costs information for the SCRs at Refinery 4 and Refinery 9 to achieve 2 ppmv and 5 ppmv NOx.[15 - 17] One manufacturer indicated that the flue gas exist temperatures at the two refineries must be raised to 650 degrees F to avoid SO2/SO3 and ABS related problems; and estimated that this would add about 10% to the overall costs of the equipment.

The EPA's OAQPS Guidelines' approach was used to estimate the following costs: [4]

Instrumental = 10% x Equipment Cost
Sales Tax = 9% x Equipment Cost
Freight = 5% x Equipment Cost
Thus, Total Equipment Cost = 1.24 x Equipment Cost = 1.24 EC
Installed Costs = 50% of Total Equipment Costs

Total Installed Costs (TIC) = (1.24 EC) + 0.5(1.24 EC) = 1.86 EC (Equation 3)

Based on its reported data, the annual operating costs of Refinery 1's SCR during its 25-year life is about 20% of the total installed costs. Staff used this 20% factor to estimate the 25-year operating costs for the new SCRs at all the refineries. Staff added a contingency factor of 1.5 to cover additional uncertainties for both the TIC and the annual operating costs.

$PWV_{\text{Ref 4, Ref 9}} = 1.5\ [(1.86\ EC) + 0.2\ (1.86\ EC)] = 3.35\ EC$ (Equation 4)

Using the EPA OAQPS Guidelines' approach, the PWVs would become $16 million and $19 million for Refinery 4 and 9 as shown in Table A.3, respectively.

Cost effectiveness (CE) was estimated as follows and is summarized in Table A.3:

CE = PWV / (ER x 365 days x 25 years) (Equation 5)

Where:

CE = Cost Effectiveness, $/ton
PWV = Present Worth Value, $
ER = Emission Reductions, tpd

The cost effectiveness in Table A.3 is estimated using Discounted Cash Flow (DCF) method. The cost effectiveness calculated based on the Levelized Cash Flow (LCF) method is about 1.65 times higher than the cost effectiveness estimated by the DCF method (e.g. $18K per ton DCF compared to $30K per ton LCF.)

Table A. 3 - Costs and Cost Effectiveness for SCRs (December 2014)

Fac ID	Emissions (tpd)	NOx (ppmv)	% Control	Emission Reduction (tpd)	PWV ($M)	CE ($/ton)
1	0.02	<2	95%	-	(41)	(10,181)
5	0.16	15	87%	0.14	< 33	< 25,259
6	0.20	6	64%	0.13	< 57	< 49,408
7	0.14	13	84%	0.12	27	25,455
4	0.22	21-23	91%	0.20	16	8,961
9	0.34	34-52	95%	0.32	19	6,537
Total reductions for Ref 4,9,5,6 and 7				**0.91**	**152**	**Avg <18,422**

Emissions for all 6 refineries = 1.08 tpd. Remaining emissions from FCCUs at BARCT for all 6 refineries = 1.08 – 0.91 = 0.17 tpd

Consultant's Analysis for SCRs and Staff's Revised Estimates for SCRs

In 2014, staff contracted Norton Engineering Consultants (NEC) to conduct a BARCT analysis for the refinery sector. [39] The NEC's analysis is included in Addendum 1. Table A.4 shows a comparison between NEC's and staff's estimates:

Table A. 4 – Comparison of SCR Costs Estimated by Staff and NEC (December 2014)

Facility ID	Staff's Estimates (note 1) ($M)	NEC's Estimates ($M)	NEC's Feed Rate Adjusted Estimates ($M)
5	<33	<46 (note 2)	<43
6	<57	<46 (note 2)	<50
7	27	42 (note 3)	37
4	16	38	38
9	19	39	37
Total	**152**	**211**	**195**

Note: 1) Staff's estimates were presented at the Jan 22, 2014 Working Group Meeting. For a 2-layer SCR configuration; 2) Estimates reflect a new SCR installation and are over-estimated because the FCCUs already have SCRs installed; 3) This FCCU will be dismantled.

NEC recommended SCRs with 3 layers of catalysts compared with staff's analysis based on refinery FCCU SCR applications currently operating with 2 layers of catalyst in the Basin. The NEC cost estimate included 2 layers of markup factors applied to the equipment costs and an overall 4.5 factor to project the total installed cost to the cost of material and labor.[6] NEC further added the cost of waste heat boiler modifications, new CEMS and additional ammonia storage. The resulting cost information was used to generate a curve to express PWV as a function of feed rate.

NEC's initial estimation of PWV was conducted using a set of refinery FCCU feed rates that were not consistent with those reported in the 2010 SOx RECLAIM staff report or by the January 22, 2014 RECLAIM Working Group presentation. The third column in Table A.4 provides the adjusted cost estimate to account for the representative refinery feed rates.

Catalyst Layers

taff used a different approach than NEC to estimate the SCR costs because Refinery 1 had achieved an emissions rate of 2 ppmv NOx with only 2 layers of catalysts. This resulted in a significant difference in the cost estimates based on 2 catalyst layers (staff) and 3 catalyst layers (NEC). To address this difference, staff adjusted the manufacture's proposed 60 barrels/day 3 catalyst-layer SCR configuration used by NEC in their estimate to a 2 catalyst-layer model. The adjustment included a 27 percent reduction in the base price to account for the 2-layer configuration (at 10 ft. per second) but then followed NEC's pricing including the 1.35 bid conditioning factor, the 1.75 labor factor and a 4.5 factor applied to the equipment cost. The adjusted estimate added the costs of the waste heat boiler modifications, additional ammonia storage, added CEMS, maintenance and catalyst replacement costs. The projected PWV for the adjusted manufacturers estimate for the 2-catalyst layer configuration is listed in Table A.5 totaling $163 million for five FCCU's.

Range of Costs and Cost Effectiveness for SCRs

In its report, NEC indicated that the factors in the EPA OAQPS Guidelines (Equation 3) were not sufficient to cover retrofitting applications at the refineries. The refineries also indicated the factors relating equipment costs to TIC should be at least 4, or higher. To reconcile this difference, staff presents the PWVs as a range of costs and cost effectiveness in Table A.5.

The staff cost effectiveness estimate is based on a 2-catalyst layer FCCU SCR application that is operating at Refinery 1. The PWV calculated for the five units totaled $152 million establishing

[6] NEC first marked-up the costs provided by the manufacturer by 35%. NEC named this markup as "bid conditioning factor" to cover the "low" bid provided by the manufacturer. NEC then added 75% increase in labor costs to the costs provided by the manufacturer. NEC did not provide any references to their markup factors and simply stated that the factors were based on their own experience.

the lower end average of the cost effectiveness at $18,000 per ton NOx reduced. The upper cost effectiveness listed in Table A.5 is derived from the PWV totals from the manufacturers adjusted 2-layer estimate averaging $20,000 per ton NOx reduced.

As previously stated, the 2-layer catalyst SCR application has been demonstrated to reach 2.0 ppmv at Refinery 1, in the Basin. Since NEC's proposed model is based on a 3-layer catalyst application it is not included in the cost effectiveness calculation presented in Table A.5. Regardless, the cost effectiveness calculated for the NEC model would place the FCCU SCR application for the 5 units at an average CE of $29,000. Thus, using the NEC 3-layer catalyst assumption, the cost effectiveness is still less than the $50,000 threshold used in the current BARCT analysis and less than the $30,800 threshold established for SCR control equipment established for boilers greater than 75 mmBtu/hr in SCAQMD Rule 1146.

Note that Refinery 4's FCCU is scheduled to be shut down in the near future which would result in lowering the costs estimated for the FCCU category.

Table A. 5 – Revised Costs and Cost Effectiveness for SCRs (March 2015)

Fac ID	Emission Red (tpd)	Staff's 2-Layer Estimate PWV ($M)	Manufacturers Adjusted 2-Layer With no Mark-Up Estimates ($M)	Manufacturers Ajusted 2-Layer with 2 Mark-Ups Estimates PWV ($M)	Range of PWV ($M)	CE ($/ton)
5	0.14	<33	<34	<36	<33 – 36	<25K - $27K
6	0.13	<57	<40	<42	<57 – 42	<49K – 36K
7	0.12	27	29	31	27 – 31	25K – 29K
4	0.20	16	22	23	16 – 23	9K – 13K
9	0.32	19	29	31	19 – 31	7K – 11K
Total	**0.91**	**152**	**154**	**163**	**152 - 163**	**18K – 20K**

Costs and Cost Effectiveness for NOx Reduction Additives

NOx reduction additives can reduce about 10% - 70% NOx emissions depending on the FCCU regenerator configuration and operating condition. The use of NOx reducing additives may not achieve the ultimate goal of 2 ppmv, but may help the refineries achieve the future facility overall shave. Cost effectiveness for NOx reducing additives were estimated to be about $6,460 per ton of NOx reduced using DCF method ($10,660 per ton using LCF method.) The inputs and results were summarized in Table A.6.[38]

Table A. 6 - Costs and Cost Effectiveness for NOx Reduction Additives

Inputs	
Baseline NOx	40 ppmv
NOx reduction	50%
Cost of NOx Reduction Additives	$15 per lb
NOx Reduction Additives	1.5% of total catalysts
Catalyst Addition Rate	4 ton per day
FCCU Rate	70 million barrels per day
Results	
NOx Reduction Additives Costs	1800 $/day
NOx Reduction	348 lbs/day
Cost Effectiveness for NOx Reducing Additives	**6,460 $/ton**

Costs and Cost Effectiveness for LoTOx Scrubbers

The FCCUs at Refinery 4 and Refinery 9 currently have no control. Refinery 7's FCCU has a scrubber. Process data for these three refineries' FCCUs were provided to a manufacturer, and the manufacturer provided estimates for the total installed costs and annual operating costs. [27]

The total installed costs provided by the manufacturer included the ozone generator, the associated closed loop chiller, cooling pump, ozone injection lances. The installed costs also included the associated platforms and access steel, some interconnecting piping and supports, valves and instruments and freight to the job site. The manufacturer did not include oxygen storage and vaporization (which was only necessary if the refinery did not yet have oxygen at the site for other uses), or the cost of electrical equipment and foundation. Staff added a contingency factor of 2 to markup the costs provided by the manufacturer to account for any additional modifications needed at the site and any variations in annual operating costs such as electricity or oxygen.

The PWV for Refineries 4, 7 and 9 LoTOx applications were estimated as follows:

$$PWV_{\text{Ref 4, 7 and 9}} = \text{Contingency Factor x } (TIC_{\text{Ref 4, 7 and 9}} + (15.62 \text{ x } AC_{\text{Ref 4, 7 and 9}}))$$

Where:

$PWV_{\text{Ref 4, 7 and 9}}$ = Present Worth Value $
$TIC_{\text{Ref 4, 7 and 9}}$ = Total Installed Costs provided by vendor, $
$AC_{\text{Ref 4, 7 and 9}}$ = Annual Operating Costs provided by vendor, $
Contingency Factor = 2

Refineries 5 and 6 currently employ SCRs to reduce their FCCU's NOx emissions. Scrubbers may be needed to reduce the SOx emissions from their FCCUs, and LoTOx can be installed concurrently with the scrubbers to further reduce NOx emissions. The PWV for LoTOx applications at Refineries 5 and 6 were estimated based on the PWV for LoTOx applications at Refineries 4 and 7 and the ratios of their appropriate inlet flue gas flow rates to the 0.7 power as follows:

$$PWV_{\text{Ref 5}} = PWV_{\text{Ref 5}} \text{ x } (\text{Flow Rate}_{\text{Ref 5}} / \text{Flow Rate}_{\text{Ref 4}})^{\wedge 0.7}$$
$$PWV_{\text{Ref 6}} = PWV_{\text{Ref 7}} \text{ x } (\text{Flow Rate}_{\text{Ref 6}} / \text{Flow Rate}_{\text{Ref 7}})^{\wedge 0.7}$$

The present worth values and cost effectiveness values are summarized in Table A.7. The average cost effectiveness is $15 K per ton using DCF method and $25 K per ton using LCF method.

The manufacturer estimated that a plot space needed for the ozone generator and accessories to be about 25 ft x 35 ft. The first LoTOx application was put in service in 1997. At that time, required a large foot print (e.g. 1st generation LoTOx application at a Texas refinery required a foot print of 30 ft x 80 ft.) The newer generation LoTOx application has a much smaller footprint (e.g. an equivalent unit to the Texas refinery application now requires only 25 ft x 30 ft).

Table A. 7 - Costs and Cost Effectiveness for LoTOx Applications (December 2014)

Fac ID	Emissions (tpd)	NOx (ppmv)	% Control	Emission Reduction (tpd)	PWV ($M)	CE ($/ton)
4	0.22	21-23	91%	0.20	19	10,767[JW1]
7	0.14	13	84%	0.12	16	15,199
9	0.34	34-52	95%	0.32	32	10,631
5	0.16	15	87%	0.14	24	18,590
6	0.20	6	64%	0.13	34	29,502
Total for Ref 4,9,5,6 and 7				**0.91**	**125**	**Avg <15,124**

Staff did not include the costs for scrubbers and waste water treatment in Table A.7. Since Refinery 5 and 6 already have SCRs, they will likely to use their SCRs to control NOx. Staff included the costs for scrubbers with waste treatment for Refineries 4, 7 and 9. Staff also estimated the overall cost effectiveness for the LoTOx/scrubbing multi-component air pollution control as shown in Table A.8.

Table A. 8 – Revised Costs and Cost Effectiveness for LoTOx Scrubbers (March 2015)

Fac ID	NOx Emission Reductions (tpd)	SOx Emission Reductions (tpd)	PWV for LoTOx ($M)	PWV for Scrubbers ($M)	Total PWV ($M)	CE (K$/ton)
4	0.20	0.20	19	91	110	30
7	0.12	0.87	16	51	67	7
9	0.32	0.58	32	90	121	15

Note: 1) SOx emission reductions were taken from Table 3-11, Chapter 3, SOx RECLAIM Staff Report, dated November 2, 2010. [40] 2) PWVs for scrubbers including waste treatment were based on information provided on Table 3-12, Chapter 3, SOx RECLAIM Staff Report, dated November 2, 2010, and a Marshall Swift Index of 1.1. [40] 3) It is assumed that retrofitting existing scrubber for Refinery 7 would cost about half of the costs estimated for the installation of the new scrubber under SOx RECLAIM project.

Incremental Costs and Cost Effectiveness

The BARCT level for the FCCUs in 2005 was set at 85% reduction. The costs for SCRs to meet 85% reductions were estimated to be $111.1 million. The emission reductions were estimated to be 0.48 tons per day. A Marshall index of 1.25 was used to raise the costs of $111.1 million dollars to current dollars of $138.88 million.

Table A.9 presents the Staff estimated the overall PWVs for 2 cases:

> <u>Case 1:</u> Assume all 5 refineries will use SCRs to achieve the proposed BARCT level of 2 ppmv. Using the low end costs for SCRs in Table A-5, the total PWVs to achieve 2 ppmv NOx level would be $152 million.
>
> <u>Case 2:</u> Assume Refineries 5 and 6 will use SCRs (using the high end costs for SCRs in Table A.5) and Refineries 4, 7 and 9 will use LoTOx and scrubbers (Table A-8) for multi-component control. The total PWVs would be $375 million.

Table A. 9 – Present Worth Values of SCRs and LoTOx/Scrubbers for FCCUs (March 2015)

Fac ID	Case 1 - PWV ($M)	Case 2 - PWV ($M)
5	<33 (SCR)	<36 (SCR)
6	<57 (SCR)	<57 (SCR)
7	27 (SCR)	67 (LoTOx and Scrubber)
4	16 (SCR)	110 (LoTOx and Scrubber)
9	19 (SCR)	121 (LoTOx and Scrubber)
Total	**152 (all SCRs)**	**391 (SCRs and LoTOx/Scrubbers)**

Incremental cost effectiveness to achieve a more stringent of 2 ppmv NOx from a less stringent level of 85% control during 25-years life of the control device is listed in Table A.10. CE is estimated as follows:

$CE_{\text{incremental}} = (PWV_{2\text{ ppmv}} - PWV_{85\%\text{ control}}) / ((ER_{2\text{ ppmv}} - ER_{85\%\text{ control}}) \times 25\text{ yrs} \times 365\text{ days})$

Where:

$CE_{\text{incremental}}$ = Incremental Cost Effectiveness, $/ton
$PWV_{2\text{ ppmv}}$ = Sum of all SCR (or LoTOx) costs to meet 2 ppmv, $
$PWV_{85\%\text{ control}}$ = Sum of all SCR costs to meet 85% reduction, $ = $139 M
$ER_{2\text{ ppmv}}$ = Total emission reductions achieved at 2 ppmv NOx, tpd
= 0.91 tpd estimated from 2011 baseline
$ER_{85\%\text{ control}}$ = Total emission reductions achieved with 85% control, tpd
= 1.08 tpd – 0.60 tpd = 0.48 tpd

Table A. 10 – Incremental Cost Effectiveness of SCRs and LoTOx Scrubbers for FCCUs (March 2015)

	Emission Reductions (tpd)	PWV ($M)
SCR for 85% control	0.48 tpd NOx	139
SCR for 2 ppmv for all 5 Refineries	0.91 tpd NOx	152
SCR for 2 ppmv for Ref 5, 6 and LoTOx/Scrubber for Ref 4,7, 9	0.91 tpd NOx and 1.65 tpd SOx	391
Case 1 – Incremental Emission Reductions = 0.91 – 0.48 = 0.43 tpd NOx Incremental Cost Effectiveness: SCR – SCR for all 5 Refineries (152 - 139) / (0.91 – 0.48) / 25 / 365 = 3,444 $/ton DCF and 5,683 $/ton LCF		
Case 2 – Incremental Cost Effectiveness: SCR – SCR for Ref 5, 6, and SCR - LoTOx for Ref 4, 7, 9 (391 – 139) / (0.91 + 1.65 – 0.48) / 25 / 365 = 13K $/ton DCF and 23K $/ton LCF		

Staff's Recommendation

Staff proposes a BARCT level of 2 ppmv NOx for FCCUs because 1) Refinery 1 FCCU's SCR has achieved-in-practice 2 ppmv NOx at 5 ppmv NH3 slip; and 2) NOx control technologies such as SCR, LoTOx, and NOx reduction additives are commercially available and can be used in conjunction to achieve 2 ppmv NOx in a cost-effective manner.

The cost information submitted by SCR and LoTOx manufacturers support that a BARCT level of 2 ppmv NOx is feasible and cost-effective for FCCUs in the SCAQMD. It should also be noted that NOx reducing additives, which can reduce 50% or more of NOx emissions, can be used in parallel with SCRs and LoTOx applications if needed.

In summary:

<u>Case 1:</u>
Total PWVs: $152 M with SCRs for all 5 refineries
Total incremental costs: $13 M
Incremental emission reductions: 0.43 tpd NOx
Incremental cost effectiveness with SCRs: 3,444 $/ton DCF or 5,700 $/ton LCF

<u>Case 2:</u>
Total PWVs: $391 M with SCRs for Refineries 5 and 6 and LoTOx/scrubbers for Refineries 4, 7 and 9
Total incremental costs: $252 M
Incremental emission reductions: 0.43 tpd NOx and 1.65 tpd SOx for 5 FCCUs
Incremental cost effectiveness: 13K$/ton DCF or 23K $/ton LCF

References for FCCUs

1. Information on Refinery 1's FCCU's SCR. Email from Refinery 1 to Minh Pham, dated October 23, 2013.

2. Air Pollution Technology Institute (APTI) Course 415 – Control of Gaseous Emissions, Student Manual, Chapter 7 – Control of Nitrogen Oxide Emissions, December 1981.

3. Source Book on NOx Control Technology, U.S. EPA, EPA-600/2-91-029, July 1991.

4. EPA Air Pollution Cost Manual, Section 4 – NOx Controls, EPA/452/B-02-001, Sixth Edition, January 2002.

5. Reducing NOx and NH3 Emissions with Advanced SCR Technology. Rita Aiello, Kevin Doura, Mike Baran, Wilson Chu, Paul Anderson, Johnson Matthey. Paper #33233. A&WMA's 107^{th} Annual Conference & Exhibition, June 24-27, 2014, Long Beach California.

6. UltraCat Catalytic Filters Remove PM, SO_2, HCl, NOx, Dioxins and HAPs. NOx Control as Low as 350 ^{o}F – TriMer's brochure – www.tri-mer.com.

7. Combating NOx from Refinery Sources Using SCR. Haldor Topsoe. Presentation at the 2^{nd} Annual World Refining Technology Summit & Exhibition, 2010, Abu Dhabi. www.topsoe.com, posted online and downloaded in January 2014.

8. Information posted online at the website for Mitsubishi and Cormetech, www.cormetech.com/non-reductionh.htm, and www.mhpowersystems.com/scr.html, downloaded on January 2014.

9. SCR and Zero-Slip TM Technology. T.W. Hastings of Cormetech, Inc. and A. Hattori of Mitsubishi Power Systems, Inc. Presentation of June 17, 2003 Turbo Expo – Atlanta, GA.

10. Dual Function Catalyst Promises High NOx Removal with Zero Ammonia Slip for Gas Turbine Applications. J.A. Rosin and H.S. Rosenberg. Power Engineering, September 2001, Vol. 105, Issue 9, page 76.

11. Optimization of Ammonia Source for SCR Applications. R. Salib and R. Keeth of Washington Group International. Paper Poster Session No. 46. (no date)

12. Comparison of Urea Based Ammonia to Liquid Ammonia Systems for NOx Reduction Applications. J. E. Fisher, WAHLCO, Inc.

13. Comparison of Urea, 19% Aqueous Ammonia, and Anhydrous Ammonia Operating Costs. of Canyon Energy Project. D. Kirk of Fuel Tech Inc. to C. McFarlin of California Energy Commission, September 3, 2008.

14. Influence Factors and Control Research on Ammonium Bisulfate Formation in the Process of Selective Catalytic Reduction. S. Ma et.al., North China Electric Power University. Journal of the Air & Waste Manuscript Paper UAWM-2013.

15. SCR Costs Information from Manufacturer A. E-mail to Minh Pham on December 26, 2013.

16. SCR Costs Information from Manufacture B. E-mail to Minh Pham on November 10, 2013.

17. SCR Costs Information from Manufacturer C. E-mail to Minh Pham on January 7, 2014.

18. Low Temperature Selective Catalytic Reduction of NOx with NH3 Using Perovskite Type Oxide Catalysts. Lishia Lai and Hsunling Baui of National Chiao Tung University and Shawyi Yan and Jungnan Hsu of Industrial Technology Research Institute, Taiwan. Paper #32657. A&WMA's 107th Annual Conference & Exhibition, June 24-27, 2014, Long Beach California.

19. LoTOx™ – Novel NOx Control Solution. Naresh J Suchak, Ph.D., Monica Caldwell, Peter Studer, Frank R Fitch, Ph.D., Linde Gases. Paper #33612. A&WMA's 107th Annual Conference & Exhibition, June 24-27, 2014, Long Beach California.

20. Meeting Tighter NOx Emission Rules – A Low Temperature Oxidation Technology Uses Ozone to Remove Very Low Levels of Nitrogen Oxide from Refinery Gases. S. Harrison, N. Suchak, F. Fitch, Linde Gases. www.digitalrefining.com/article/1000954. PTQ Q3 2014

21. Wet Scrubbing-based NOx Control Using LoTOx Technology – First Commercial FCC Start-Up Experience. Nicholas Confuorto of BELCO Technologies, Jeffrey Sexton of Marathon Petroleum Company LLC. www.digital refining.com/article/1000812. September 2007

22. Preparing Wet Scrubbing Systems for a Future with NOx Emission Requirements. S. Eagleson and N. Confuorto, BELCO Technologies Corporation, www.digitalrefining.com/article/100833. September 2013.

23. Low Temperature Oxidation System. California Air Resources Board Grant Number ICAT 99-1. www.arb.ca.gov/research/icat/projects/boc.htm#.

24. Pilot-Scale Studies on NOx Removal from Flue Gas Via NO Oxidation and Absorption into NaOH Solution. M. Jakubiak, W. Kordylewski. Wroclaw University of Technology, Faculty of Mechanical and Power Engineering, Institute of Power Engineering and Fluid Mechanics, Poland.

25. Acid Gas Scrubber for Multi-Pollutant Reduction. Nicholas Confuorto, BELCO. Institute of Clean Air Companies (ICAC) - Emission Control and Measurement Workshop, March 24-25, 2010.

26. LoTOx NOx Reduction Technology Installation List. Dupont BELCO Clean Air Technologies, dated May 2013.

27. Costs for LoTOx Applications to Meet 2 ppmv NOx for 3 FCCUs and Coke Calciner in the SCAQMD. Email of information provided by LoTOx manufacturer to Minh Pham, dated December 12, 2013 and January 20, 2014.

28. Best Practices for In-Situ SOx and NOx Emission Control in FCC Units. Todd Hochheiser, Bart de Graaf, Paul Anderson. Johnson Matthey. Paper #33231. A&WMA's 107th Annual Conference & Exhibition, June 24-27, 2014, Long Beach California.

29. HCN and NOx Control Technologies in the FCC – Results of Research into Emissions from the FCC, plus Guidance on How to Obtain the Minimum Level of NOx Emissions from Full Burn FCC. Xunhoa Mo, Bart de Graaf, Charles Radcliffe, and Paul Diddams, Johnson Matthey, Process Technologies, Intercat/JM Additives.

30. FCC DeSOx and DeNOx Additive Technology. Wwn Bin, He Min-Yuan. Research Institute of Petroleum Processing, Beijing China. Journal of Environmental Scineces. Vol. 12, No. 3, pp.310 – 318, 2000.

31. FCC Flue Gas Scrubber Alternatives: Part I. Intercat/Johnson Matthey. 2009. www.digitalrefining.com.

32. Reducing FCC Unit NOx Emissions. Intercat/Johnson Matthey. www.digitalrefining.com.

33. Controlling FCC NOx Emissions. Grace Technology Conference in Munich. September 2011. www.refiningoperations.com.

34. FCC Catalysts and Additives for Costs and Emission Control. Grace Technologies. www.digitalrefining.com.

35. Reduce FCC Regenerator SOx and NOx Emissions. RefineryOperations.com, Vol: 2, Iss: 7, April 20, 2011.

36. Products and Performance Data of BASF CLEANOx. www.basf.com.

37. CLEANOx FCC NOx Reduction Additives. BASF. www.catalysts.basf.com/refining and information provided to Minh Pham on February 7, 2014.

38. Costs Analysis for NOx Reduction Additives. Information from a manufacturer of NOx Reduction Additives to Minh Pham. February 21, 2014.

39. BARCT Analysis for SCAQMD NOx RECLAIM, Non-Confidential Report, Norton Engineering, November 26, 2014 (See Addendum 1)

40. SCAQMD's Final Staff Report for SOx RECLAIM – Part I - BARCT Assessment & RTC Reductions Analysis, November 2, 2010.

Appendix B – Refinery Boilers and Process Heaters

Process Description

Boilers and process heaters are used extensively in almost all of the processes in refinery such as distillation, hydrotreating, fluid catalytic cracking, alkylation, reforming, and delayed coking. Figure B.1 provides a simplified diagram of the processes where boilers and heaters are used. There are 23 boilers and 189 heaters in the refineries classified as major or large NOx sources. The refinery heaters and boilers primarily burn refinery gas which is generated at the refinery. Most of these boilers and heaters use natural gas as back-up or supplemental fuel. Liquid fuel or solid fuel is rarely used in refinery boilers and heaters. The combustion of fuel generates NOx, primarily "thermal" NOx with small contribution from "fuel" NOx and "prompt" NOx.

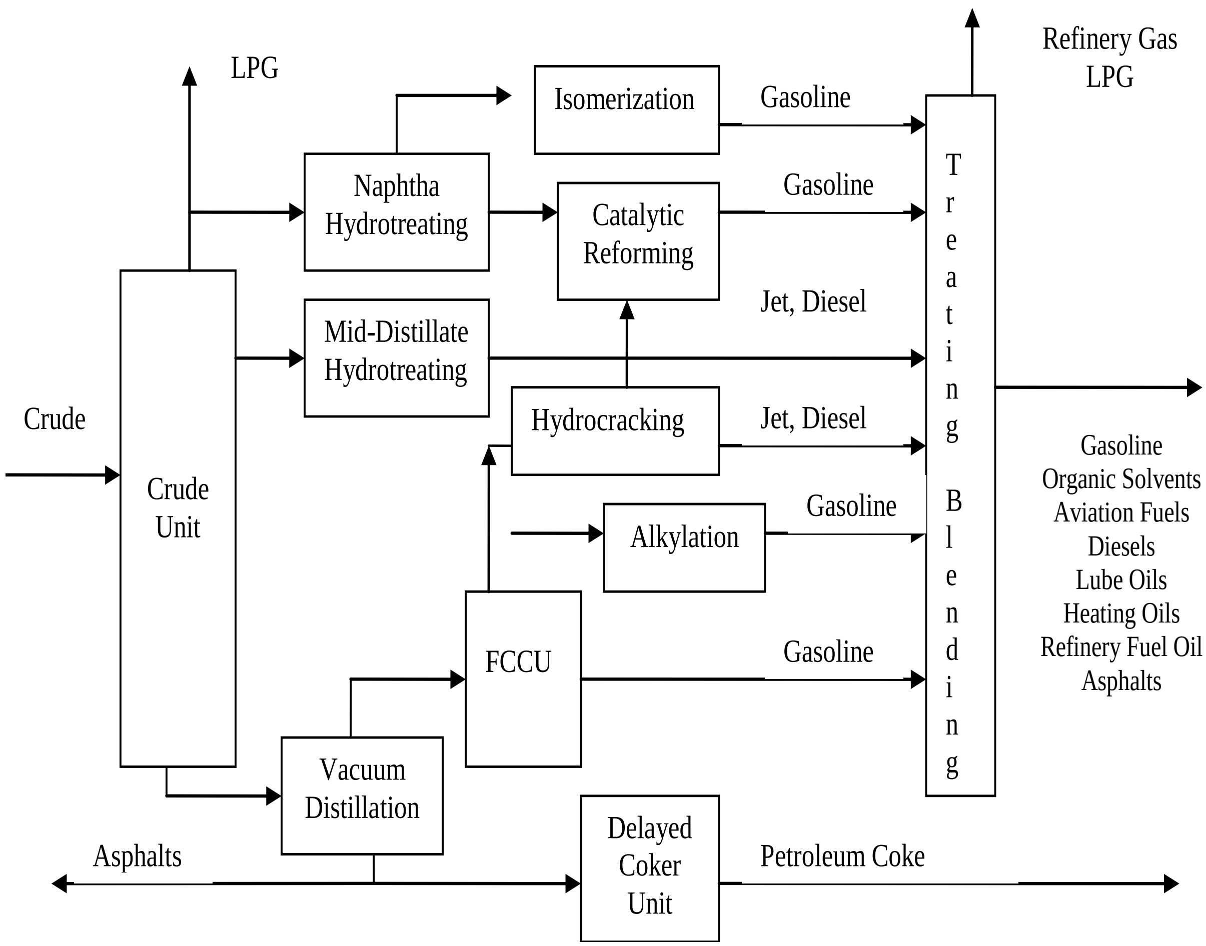


Figure B. 1 - Refinery Processes

Emission Inventory

There are a total of 212 boilers and heaters classified as major and large NOx sources at the refineries. The distribution of boilers and heaters and their emissions are shown in Table 5.1. Collectively, the 212 boilers and heaters emitted about 7.39 tons per day in 2011. Their NOx concentrations at the stack vary from 1.6 ppmv for units equipped with selective catalytic reduction (SCR) to 120 ppmv for units with no control.

The 2005 RECLAIM amendments set BARCT levels between 5 ppmv to 12 ppmv for various categories of boilers and heaters. A comprehensive list of equipment specific NOx emission limits is provided in Table 3 of the SCAQMD Rule 2002, amended January 7, 2005. As a component of the BARCT assessment, the decision was made to retain the 2000 BARCT level for boilers/heaters with maximum input rating between 40-100 mmBtu/hr at 25 ppmv. In 2005, it was estimated that 51 boilers/heaters would require SCRs to be installed to reduce NOx emissions. Only 4 pieces of equipment were retrofitted with SCRs; these were in response to either an EPA consent decree or an order of abatement. If all of the boilers and heaters had complied with the 2005 BARCT emissions from boilers and heaters would be reduced from 7.39 tons per day to 1.92 tons per day, approximately 74% reduction in emissions.

Achieved-In-Practice NOx Levels for Boilers and Heaters

The following is a summary of refinery boilers and heaters that have very low emission levels:

- Fourteen process heaters using refinery fuel gas in the SCAQMD ranging from 22 to 653 mmBtu/hr equipped with SCRs have achieved 1.6 - 3.5 ppmv NOx at 3% O_2;

- Two boilers, 400 HP and 1000 HP, using natural gas, equipped with LoTOx scrubbers have achieved 2 - 5 ppmv NOx at 3% O_2;

- A crude heater using refinery fuel gas rating at 10 mmBtu/hr in Coffeyville refinery Kansas has been operated at 3 - 8 ppmv NOx at 3% O_2 with Great Southern Flameless technology without the use of SCR.

All of the control technologies mentioned above are commercially available and can be designed to reach 2 ppmv NOx at 3% O_2.

Control Technology

Commercially available control technologies are SCRs, Great Southern Flameless Heaters, and LoTOx applications with scrubbers. Other potential technologies on the horizon are ClearSign, Cheng Low NOx and KnowNOx. SCR, Great Southern Flameless burners and ClearSign burner technologies are discussed below. Cheng Low NOx, LoTOx and KnowNOx technologies are discussed in other Appendices. Other common control technologies such as Low NOx burners, Ultra Low NOx burners, or Selective Non Catalytic Reduction (SNCR) are not discussed here.

Selective Catalytic Reduction

SCR is an effective control technology for NOx which uses ammonia (NH_3) to selectively reduce NOx to nitrogen through the following reactions.

Great Southern Flameless Heaters

In 2012, Coffeyville Resources purchased the world's first flameless crude heater designed by Great Southern Flameless for their Coffeyville refinery in Kansas to comply with a Consent Decree issued by the U.S. EPA. The flameless heater has been in operation for over one year and has achieved-in-practice 5 ppmv NOx at 3% O2 with pilots in operation, and 3 ppmv NOx without pilots for flameless technology. Great Southern Flameless confirmed the following: [18-21]

- Flameless heaters can be designed to achieve:
  - 5 ppmv NOx at 3% O_2; or
  - 2 ppmv NOx at 3% O_2 with pilots off during flameless firing and with a fuel mix of 25% natural gas and 75% refinery gas.

- Oxy-fuel flameless heaters can be designed to achieve:
  - 2 ppmv NOx at 3% O_2; or
  - 1 ppmv with pilots off during flameless firing

Great Southern Flameless can supply flameless heaters or oxy-fuel flameless heaters with maximum rating from 10 mmBtu/hr to 320 mmBtu/hr (240 mmBtu/hr process duty.) Their production capacity is 30 heaters per year. The modules are designed and fabricated in Oklahoma, shipped in pieces to be field, and assembled at the site. The heaters can use the same foundation of the conventional heaters. The flameless heater designed by Great Southern Flameless for the Coffeyville refinery has the following characteristic:

- The heater is a polygon with the process coil (heat exchanger tubes) in the center and two "Flameless Nozzle Grouping" (FNG) located on the wall which fire tangentially. Each FNG consists of 2 conventional nozzles, 2 flameless fuel nozzles, 4 air nozzles and 1 nozzle for pilot fuel.

- To pin the flue gas in circulation against the wall, Great Southern Flameless developed and patented a proprietary design for the heater's interior wall. The interior wall of the heater has a dimple pattern in the refractory which holds the flue gas to the wall and allows the flue gas to circulate in high volume and velocity around the heater until it eventually rotates out to the center of the heater, and up through the uptake ducts and into the convection section of the heater. This unique wall design eliminates hot gas impingement on the process coil located in the center of the heater and assures even heat radiation from the heater walls to the heat exchanger tubes.

- Great Southern Flameless also developed and has a patent pending for an automated 3-way switching valve. This valve allows the heater to be operated in three different firing modes:
  - Conventional firing mode when all fuel gas is diverted to the 2 conventional nozzles;
  - Staged firing mode when half of the fuel gas goes to the 2 conventional nozzles and the other half goes to the 2 flameless nozzles; and
  - Flameless firing mode when all fuel gas goes to the 2 flameless nozzles and the combustion is sustained by the high temperatures of the combustion air.

- The heater has a balanced draft air-preheat system which generates high temperature combustion air. High temperature combustion air is required for the staged firing mode and the flameless firing mode to maintain the high auto-ignition temperature required for combustion.

From cold start, the heater is brought up in natural draft mode in the same manner as any typical conventional heater. The firing rate of the heater is gradually increased to the required level while the combustion air is gradually increased to 850 degrees F. Once the combustion air temperature exceeds 850 degrees F, it will sustain the automatic ignition of fuel, and the heater is transitioned into the staged fuel firing mode with pilots off-line. The heater is operated in the staged firing mode until steady state operation is achieved. At this point, the heater is transitioned into flameless firing mode. Visible flame from the conventional nozzles disappears and NOx emissions decreases significantly in the flameless mode operation.

Table B.1 below tabulates the temperature profile inside the heater under the three modes of firing. With more even temperature distribution, the flameless firing mode results in 4 ppmv NOx compared to 77 ppmv NOx under conventional firing and 49 ppmv under staged firing mode. The Coffeyville heater average NOx emissions are in the levels of 3 – 8 ppmvd without the use of high temperature high energy SCR system.

The heater can be designed for combustion with oxygen. Combustion with oxygen in place of air will eliminate "prompt" NOx and reduce CO_2 emissions. Figure B.2 shows a flameless heater modified for oxygen combustion. Table B.2 lists the predicted performance of an oxy-flameless heater. Flameless and oxy-flameless heaters come in modules and can be stacked up to 320 mmBtu/hr rating.

Table B. 1– Temperature Zones and NOx Emissions of Great Southern Flameless Heater

	Conventional Firing	Staged Firing	Flameless Firing
Combustion Air Temperature, degrees F	804	893	909
Average Radiant Upper Level Temp, degrees F	1544	1740	1714
Average Radiant Mid Level Temp, degrees F	2050	1826	1476
Average Radiant Lower Level Temp, degrees F	1488	1627	1669
Excess Oxygen, %	3.7	2.6	2.4
NOx, ppmv	77	49	4

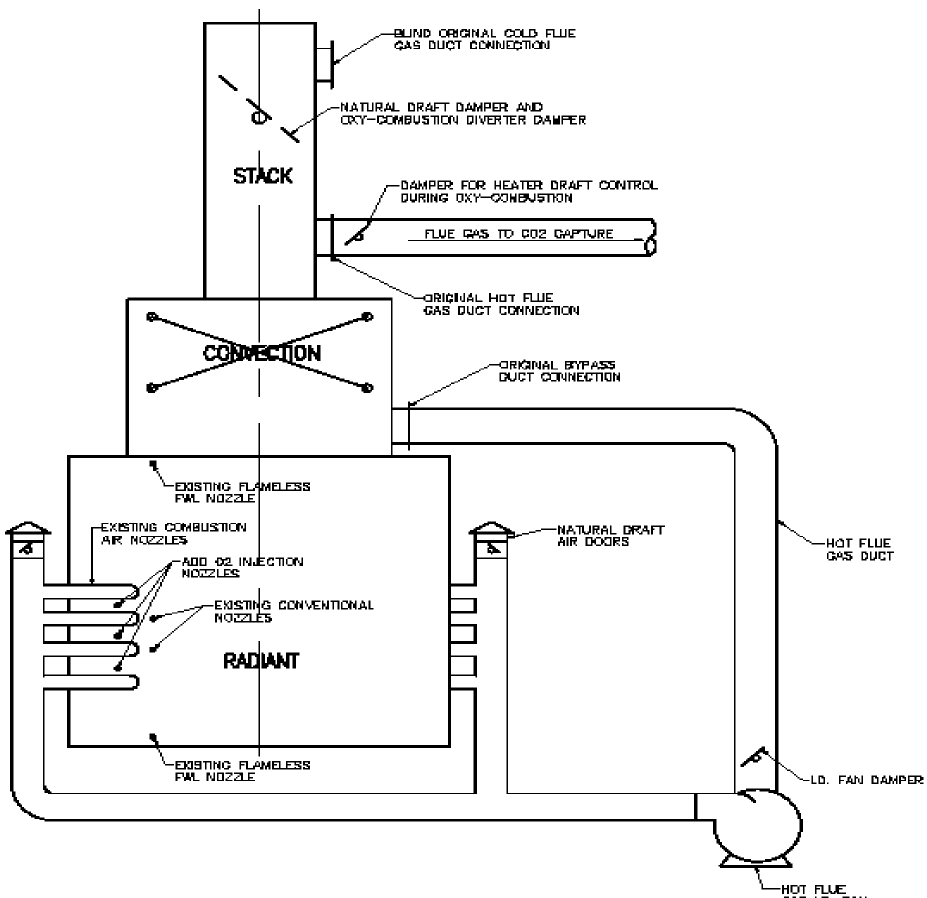


Figure B. 2 - Oxy-Flameless Heater (Reference 17)

Table B. 2 – Predicted Performance of Great Southern Oxy-Flameless Heater

	Traditional Heater	Flameless Heater	Oxy-Flameless Heater
NOx, ppmv	31	4-8	0-1
Excess Oxygen, %	3	3	3
NOx, lb/mmBtu		0.0106	0.0021 or below

ClearSign Technology

ClearSign Combustion Corporation in Seattle has developed two technologies applicable for boilers and heaters: DUPLEX™ technology and Electrodynamic Combustion Control (ECC™). ClearSign expected that these technologies would generate low concentrations of NOx and CO without the need for flue gas recirculation (FGR), SCR or high excess air operation.

DUPLEX™ technology can be installed in new boilers or heaters, or retrofit in existing boilers and heaters. The DUPLEX technology comprises a proprietary DUPLEX tile installed downstream of conventional burners. The hot combustion flame from the conventional burners impinges onto the DULEX tile, and the tile helps radiate heat evenly with high emissivity to the combustion products. DUPLEX operation also creates more mixing and shorter flames. Since the flame length is one parameter that limits the total heat release in a furnace, decreased flame length can allow for significantly higher process throughputs. DUPLEX tile is expected to have a 3- to 5-year life. A demonstration project with San Joaquin Air Pollution Control District and efforts of scaling up the technology to heaters of 5 - 50 million BTU/hr are underway. [20]

The Electrodynamic Combustion Control (ECC™) uses an electric field to effectively shape the flame, accelerate flame speed, and improve flame stability. The total electrical field power required to generate such effects is less than 0.1% of the firing rate.

Bench test performance estimates for DUPLEX and ECC indicated that NOx and CO were less than 5 ppmv, when furnace temperatures were steady maintained between 1200 and 1800 ^{o}F. Beside the benefits of reducing air pollution, ClearSign believes that their burners will provide substantial economic benefits from more uniform heat distribution, improved process throughput, and potentially reduced maintenance costs. [22-23]

Costs and Cost Effectiveness for SCRs

Staff developed a cost curve that plots the PWV of the control devices as a function of boiler/heaters' maximum rating utilizing the following sets of data:

- Refinery Survey Data
- Refinery Consultant's Analysis
- Data provided by three SCR manufacturers, Great Southern Flameless and ClearSign.

The PWVs determined from the cost curve were used to estimate the costs and cost effectiveness for all 212 boilers/heaters at the refineries. The details follow.

Survey Data

As a component of the RECLAIM BARCT evaluation, a survey was submitted to the refineries in 2013 requesting cost information for their boilers and heaters operated with SCRs. There are 14 heaters at the refineries that currently achieve between 1.6 ppmv and 3.5 ppmv NOx at 3% oxygen with the use of SCRs. Table B.3 lists several key characteristics of the heater/SCR combination including: the 2011 emissions, the NOx concentration measured at the stack, the heater maximum rating, and the year of SCR installation, the equipment costs (in the year of installation), installation costs (in the year of installation), and annual operating costs reported by the refineries. [13] A Marshall Index was used to bring the reported costs to the present dollars. Several heaters share a control device. Where this occurs, staff apportioned the reported costs for SCRs into individual SCR costs for each heater based on their relative maximum input ratings. The PWV of individual heaters are estimated using Equation 1 and 2.

PWV = (TIC + (15.62 x AC)) x Marshall Index (Equation 1)

Where:

PWV = Present Worth Value, $
TIC = Total Installed Costs, $
AC = Annual Operating Costs, $. The catalyst replacement costs were reported as a part of the annual operating costs

$PWV_{\text{Heater A}} = PWV * R_{\text{Heater A}} / R_{\text{All Heaters}}$ (Equation 2)

Where:

$PWV_{\text{Heater A}}$ = Present Worth Value of Heater A
$R_{\text{Heater A}}$ = Maximum Rating of Heater A
$R_{\text{All Heaters}}$ = Total Maximum Rating of All Heaters

From the set of all 14 data points above, staff obtained the following ratios:

Installation Costs = 2.807 x Equipment Costs
Total Installed Costs = 3.870 x Equipment Costs
Present Worth Values = 4.072 x Equip Costs = 1.052 x Total Installed Costs (Equation 3).

Table B. 3 – Costs of SCRs Estimated Based on Information Submitted by Refinery

Device	Process	mmBtu/hr	2011 Emissions (Tons)	Existing NOx ppmv at 3% O2	Shared Control	PWV ($M)
Heater	FCCU	51	13.5	59	Yes	2.56
Heater	FCCU	39	8.24	59	Yes	1.96
Heater	Crude	350	68.6	33	No	6.84
Heater	Crude	154	15.82	20	No	6.02
Heater	Cat Reform	116	10.32	33	Yes	3.89
Heater	Cat Reform	68	7.31	33	Yes	2.83
Heater	Cat Reform	71	5.12	33	No	2.38
Heater	Cat Reform	56	6.09	33	Yes	1.88
Heater	Cat Reform	19	0.8	33	Yes	0.64
Heater	Cat Reform	110	48.64	75	Yes	3.7
Heater	Cat Reform	100	16.17	75	Yes	3.36
Heater	Cat Reform	70	25.73	75	Yes	2.35
Heater	Cat Reform	42	21.16	75	Yes	1.41
Heater	Cat Reform	24	13.1	75	Yes	0.81
Heater	H2 Production	340	70.32	34	No	20.41
Boiler 11	Steam Generation	352	58.99	56	No	15.04
Boiler 8	Steam Generation	179	32.48	85	No	9.99
Boiler 6	Steam Generation	250	61.66	75	No	12.2

Refinery's Consultant Study

A refinery provided information to SCAQMD staff from a study conducted by their consultant. This study estimated actual costs to install SCRs for 18 heaters at the refinery. The heaters have capacity ranging from 39 - 352 mmBtu/hr. Several heaters were to share a common SCR. The estimated PWVs for these 18 heaters were calculated using the refinery consultant's estimates for the total installed costs and a multiplier factor of 1.052 (Equation 3). The PWVs of common SCRs were apportioned as individual SCR costs for individual heaters using the heater maximum ratings. The PWVs for 18 heaters are summarized in Table B.4. [14]

Table B. 4 – Performance and Cost Information of SCRs for Process Heaters from Refinery Survey

Process	mmBtu/hr	2011 Emissions (Tons)	Year of Installation	Existing NOx ppmv (3% O2)	Shared Control	Equipment Cost ($M)	Installation Cost ($M)	Marshall Index	PWV ($M)
Crude	85	0.42	2008	3.5	No	0.76	0.72	1.09	2.87
Hydrotreating	28	1.29	2007	2.7	Yes	0.42	0.18	1.13	0.99
Hydrotreating	22	0.55	2004	2.7	Yes	0.42	0.18	1.13	0.78
Hydrotreating	13	0.42	2007	2.7	Yes	0.42	0.18	1.13	0.45
Coking	176	17.06	1992	2.7	Yes	2.76	6.83	1.64	5.39
Coking	176	17.15	1992	2.7	Yes	2.76	6.83	1.64	5.39
Coking	176	20.79	1992	2.7	Yes	2.76	6.83	1.64	5.39
Cat Reform	177	1.08	1994	1.6	Yes	1.95	5.85	1.56	3.88
Cat Reform	125	0.89	1994	1.6	Yes	1.95	5.85	1.56	2.74
Cat Reform	88	0.53	1994	1.6	Yes	1.95	5.85	1.56	1.93
Cat Reform	199	1.43	1994	1.6	Yes	1.95	5.85	1.56	4.36
H2 Production	653	8.93	2000	2.7	No	7.65	22.95	1.42	44.12
Crude	83	0.86	2001	2.7	No	7.5	22.5	1.42	43.27
Hydrotreating	78	0.27	2003	2.3	No	4.98	14.93	1.38	28.11

Note: Staff used all 14 data points to estimate the ratios of 2.807, 3.870 and 4.072 in Equation 3 however staff did not include data point #13 and #14 on Figure B.3 since the costs of these data points are out of the norm (e.g. data point #13 of $43 million for a 83 mmBtu/hr heaters as compared to data point #12 of $44 million for 653 mmBtu/hr heater.)

SCR Manufacturers

All SCR manufacturers that staff contacted confirmed the following:

- It is feasible to achieve 2 ppmv NOx at 5 ppmv ammonia slip; and
- The costs for SCRs to achieve 2 ppmv NOx is about 10% higher than the costs of SCRs to meet 5 ppmv NOx.

Three SCR manufacturers provided SCR equipment costs. Staff used a multiplication factor of 4 to estimate the PWVs using Equation 3 and the actual reported costs from several refineries submitted in response to the SCAQMD survey.

After refinery visits, a multiplication factor of 4 was used to estimate the TIC (not PWV) as recommended by several refineries to reflect the difficulty of installing SCR for retrofit applications. [15-17] In addition, the following costs were added to the TIC of the SCRs listed in Table B.5:

- Induced draft fans:
  - $1.26 M for 100 mmBtu/hr heater,
  - $1.69 M for 163 mmBtu/hr, and
  - $2.67 M for 350 mmBtu/hr as estimated by NEC [24]
- Ammonia tanks: $1.5 M per NEC recommendation [24]
- CEMS: $100,000 based on data submitted to the SCAQMD in previous CEMS applications.

Great Southern Flameless

Great Southern Flameless provided costs data based on the following assumptions, and the results are summarized in Table B.6 and Table B.7. [20-21]

- 5 ppmv NOx outlet concentration for standard flameless heater
- 3 ppmv NOx outlet for standard flameless heater with pilots off during flameless firing
- 2 ppmv NOx outlet for standard flameless heater with pilots off during flameless firing and fuel conditioning (25% natural gas and 75% fuel gas)
- 1 ppmv NOx outlet concentration for standard oxy-fueled flameless heater
- The equipment costs include burner management system (BMS) control
- Oxygen costs is estimated at $70 per ton for 93% oxygen concentration
- There is no difference in costs between the 2 ppmv and 5 ppmv NOx flameless heaters
- The PWV was estimated based on 4% interest rate and 20-25 years life for heaters
- The PWV for standard flameless includes the savings due to increase in efficiency (83% to 91%) over the conventional heaters
- The PWV for standard oxy-fuel flameless is based on 20% (mass) injection of O2 and includes the savings due to operating efficiency increase (83% to 93.5%)

Table B. 5 - Costs of SCRs Estimated Based on Information from SCR Manufacturers

	Unit Rating (mmBtu/hr)	NOx in (ppmv)	NOx out (ppmv)	Equip Cost ($ M)	PWV ($ M)	NH3 (lb/hr)
A	163	80	2	0.13	0.52 – 3.81 (note 7)	10
	163	80	2	0.10 (NH_3 Slip Cat)	0.4 – 3.99 (note 7)	10
B	100	100	5	0.27 (note 1)	1.08 – 3.94 (note 7)	17
	100	100	2	0.30	1.30 – 4.16 (note 7)	17.5
	350	100	5	0.33 (note 2)	1.30 – 6.0 (note 7)	57
	350	100	2	0.38	1.50 – 6.0(note 7)	59
C	100	100	5	0.20 (note 3)	0.80 – 4.0 (note 7)	5.8
	100	100	2	0.22	0.88 – 4.0 (note 7)	6.0
	350	100	5	0.65 (note 4)	0.26 – 4.53 (note 7)	17.5
	350	100	2	0.70	0.28 – 4.55 (notes 5,7)	17.8

Note: 1) SCR replacement costs were estimated to be $10,000 - $15,000 every 3 – 5 years; 2) SCR replacement costs were estimated to be $20,000 - $25,000 every 3 – 5 years; 3) SCR replacement costs were estimated to be $23,000 - $24,000 every 6 to 7 years ; 4) SCR replacement costs were estimated to be $70,000 - $72,000 every 6 to 7 years; 5) Manufacturer C also estimated annual operating costs based on ammonia costs of about $800 per ton, and using this data, the PWV of the SCR for the 350 mmBtu/hr heater to meet 2 ppmv would be $2,218,040 million which is in the range of $2,800,000 estimated by using the multiplier factor of 4 and the equipment costs provided by the manufacturer. 6) Ammonia slip is 5 ppmv in all categories listed in Table B-6. 7) The high end of the range includes the costs of SCR, induced draft fan, ammonia tank, and new CEMS.

Table B. 6 – Costs for Great Southern Flameless Heaters

Fired Duty HHV (mmBtu.hr)	Equipment Costs ($)	Installation Costs ($)	Total Installed Costs ($)
32	1,909,005	3,818,010	5,727,015
117	3,813,040	7,626,080	11,439,120
187	4,345,000	8,690,000	13,035,000
321	5,332,800	10,665,600	15,998,400

Table B. 7 - Costs for Great Southern Flameless Heaters with Fuel Savings

Fired Duty HHV (mmBtu/hr)	PWV for Flameless Heater 2 ppmv NOx ($ M)	PWV for Oxy-Fuel Flameless 1 ppmv NOx ($ M)
32	4.9	10
117	7.8	22
187	7.0	32
321	5.5	50

ClearSign

ClearSign provided the estimates summarized in Table B.8 for DUPLEX burners to achieve 5 ppmv NOx and also 2 ppmv NOx. Note that their estimates did not yet include the economic benefits for more uniform heat distribution or improved process throughput and potential reduced maintenance costs. ClearSign indicated that their cost estimates were conservative and can be adjusted due to market demand. In addition, ClearSign provided an analysis showing the revenue savings of about $36,000 per ton NOx reduced using DUPLEX burners compared to SCR to achieve the proposed BARCT levels. [23]

Table B. 8 - Costs for DUPLEX Burners

Maximum Input Rating (mmBtu/hr)	PWV for 2 ppmv DUPLEX ($ M)	PWV for 5 ppmv DUPLEX ($ M)
12	0.442	0.102
24	0.884	0.204
48	1.767	0.408
96	3.535	0.815
150	5.523	1.274
200	7.292	1.682
400	14.728	3.397

Present Worth Values and Cost Effectiveness

The aggregated control equipment cost data for the boilers and heaters was sorted into 5 categories based on maximum firing rate and a representative maximum PWV for the control equipment in the category was set. Two sets of costs per firing rate were developed: one set for a 5 ppmv emissions rate and a second group for a 2 ppmv emissions limit.

For 5 ppmv SCR:

$5 M for ≤ 100 mmBtu/hr boilers and heaters
$10 M for > 100 – 200 mmBtu/hr boilers and heaters
$20 M for > 200 – 400 mmBtu/hr boilers and heaters
$30 M for > 400 – 600 mmBtu/hr boilers and heaters
$45 M for > 600 mmBtu/hr boilers and heaters

Per manufacturer's recommendation, the representative PWV cost for each category was multiplied by a factor of 1.1 for the 2 ppmv limit. A cost curve was then constructed relating the PWV for the control devices as a function of boiler/heater maximum rating determined from the five sets of data shown above. Figure B.3 illustrates the linear cost curve and distribution of control equipment by PWV/firing rate. PWVs were estimated for each boiler/heater (from the 212 pieces of equipment in the inventory) using the linear equation.

For 2 ppmv SCR:

$5.5 M for units with maximum rating ≤ 100 mmBtu/hr
$11 M for units with maximum rating > 100 – 200 mmBtu/hr
$22 M for units with maximum rating > 200 – 400 mmBtu/hr
$33 M for units with maximum rating > 400 – 600 mmBtu/hr
49.5 M for units with maximum rating > 600 mmBtu/hr

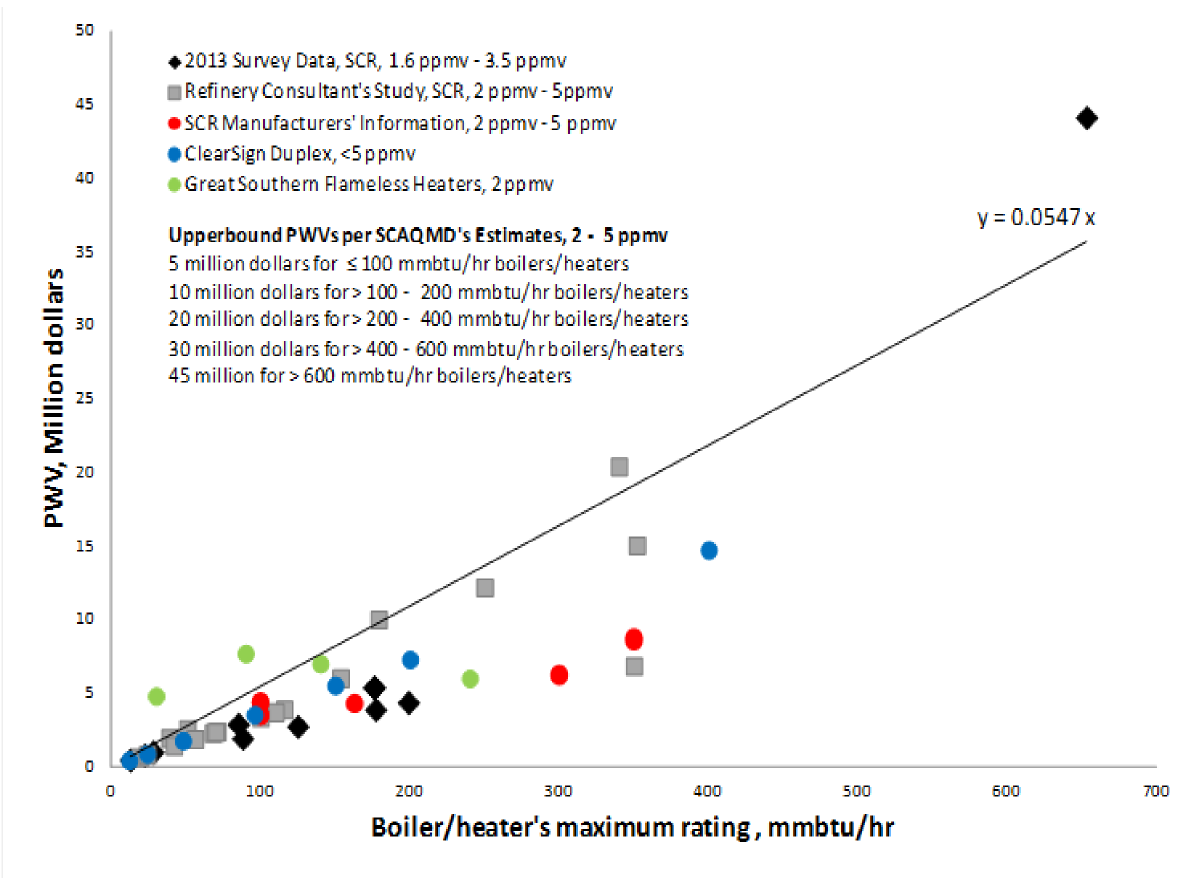


Figure B. 3 – Revised PWVs of Control Devices for Refinery Boilers/Heaters (March 2015)

Incremental Cost Effectiveness was estimated as follows based on the Discounted Cash Flow (DCF) method. A multiplication factor of 1.65 was used to estimate the cost effectiveness using the Levelized Cash Flow (LCF) method:

CE = PWV / (ER x 365 days x 25 years)

Where:

CE = Incremental Cost Effectiveness, $/ton
PWV = Present Worth Value, $
ER = Incremental Emission Reductions, tpd

Units with cost effectiveness exceeding $50,000 per ton were excluded from estimating the total emission reductions and the average cost effectiveness for the category of boilers and heaters. Staff estimated there would be 103 units that would be cost effective with total PWVs of $254.5 Million and an average cost effectiveness of $27 K per ton NOx reduced as of December 2014.

Consultant's Analysis for SCRs

NEC concurred that the 2 ppmv BARCT level is feasible for refinery boilers/heaters >40 mmBtu/hr. However, NEC recommended using SCRs with 4 layers of catalysts. NEC stated:

> "NEC feels that 2 ppmv NOx at 3% O_2 and 5 ppmv ammonia slip is an achievable BARCT level. If the refinery heaters and boilers were only burning natural gas, this 2 ppmv NOx level could be achieved by installing three SCR catalyst beds in series. However, to improve the NOx removal efficiency while burning RFG, which is necessary as all of the heaters routinely operate in this mode, NEC recommends the addition of an Ammonia Slip Catalyst (ASC) bed downstream of the third SCR bed to enhance performance. The ASC bed will permit the SCR to operate with higher ammonia loadings when needed and still guarantee the 5 ppmv ammonia slip. An additional complication in controlling the NOx level on refinery heaters is that many of them have duties that change significantly over short periods of time due to process and feed variations. The ASC bed will also alleviate this difficulty."[24]

NEC estimated their cost profile based on data provided by a manufacturer for a FCCU's SCR, upgrading the base cost for a 2-catalyst layer SCR to a 4-catalyst layer model. As with the FCCU example, the manufacturer's cost proposal was adjusted by a 1.35 factor for bid conditioning followed by a 1.75 factor for labor and a 4.5 factor to estimate the total installed cost. The NEC 4-catalyst layer model added the costs of an induced draft fan, CEMS and an ammonia injection system to their prototype SCR. The resulting profile was sized for a series of heating rates to establish cost curve that related PWV to mmBtu. Their cost equation was applied to the same boiler heater data set to estimate the cost effectiveness of achieving a 2 ppmv emissions rate.

The difference between the staff and NEC cost estimates are greatest for the units less than 200 mmBtu/hr where the staff estimate is roughly half of the NEC estimate (e.g., for 125 mmBtu/hr, staff: $11 million and NEC: $18 million). For heating values approximately 300 mmBtu/hr and higher the costs estimate converge (e.g., for 525 mmBtu/hr, staff: $33 million and NEC: $32.7 million). The impact of applying the NEC algorithm resulted in higher costs for the units with lower firing rates and as a result only 48 heaters/boilers became cost-effective. A comparison between NEC and staff's results are tabulated in Table B.9.

Table B. 9 - Comparison of NEC's and Staff's Cost Estimates for SCRs (December 2014)

	Staff's Estimates	**Staff's Estimates with NEC's Cost Information**
Total Boilers and Heaters	212	212
Number of Cost-Effective Units	103	48
Total PWVs for Cost-Effective Units	$254.5 M	$162 M
Total Emission Reductions	1.05 tpd	0.61 tpd
Average Cost Effectiveness	$27 K per ton DCF	$29 K per ton DCF

It is important to acknowledge that the two approaches were similar in relating firing rate to PWV to estimate cost effective SCR applications. However the underlying the costs, including the sizing of the SCR catalyst layer configuration (1 to 4 layers) were distinctly different. Both assumptions yield estimates to achieve a 2 ppmv emissions target. The average cost effectiveness is essentially the same and less than the $30,800 thresholds established for SCR control equipment established for boilers greater than 75 mmBtu/hr in SCAQMD Rule 1146. The difference in total emissions reduced by the two methodologies is 0.44 TPD.

Upon review of NEC's analysis, staff agreed with the following recommendations from the refineries and revised its cost analysis accordingly:

1. The refineries requested staff to use a factor of 4 (not of 3, which was a combination of the 1.86 factor recommended in the EPA OAQPS Guidelines and 50% added contingency) to estimate the installed costs from the equipment costs provided by the manufacturers. Staff agreed with this recommendation and revised the calculated PWVs based on the manufacturers' information. Revised PWVs are included in Figure B.3 above.

2. For heaters <110 mmBtu/hr with existing SCRs, the refineries requested staff to consider the full costs of SCR installations, not the "incremental" costs in estimating the cost effectiveness values. Staff concurred with this request.

Staff's revised costs and cost effectiveness estimate are summarized in Table B.10. Table B.11 provides the details of the application of the revised methodology to the affected boilers and heaters. The revised analysis results in slightly lower incremental emission reductions and a nominal increase in cost. This revision modified the difference in total NOx emissions reduced by the staff and NEC methodologies to a new total of is 0.33 TPD. Note that an adjustment is proposed to reduce the overall NOx RECLAIM shave amount to account for uncertainties in the BARCT analysis related to these different methodologies. The proposed adjustment is significantly larger than 0.33 TPD.

Table B. 10 – Revised Cost Estimates of SCRs for Boilers and Heaters

Total Boilers and Heaters	212
No of Cost-Effective Units (<50,000 $/ton)	82
No of SCRs	75 (24 upgraded, 51 new)
Total PWVs for Cost-Effective Units	237
Total Emission Reductions	0.94 ton per day
Average Cost Effectiveness	28 K $/ton DCF, 45 K $/ton LCF

Staff's Recommendation

Staff proposes to set a new BARCT level of 2 ppmv NOx for refinery boilers/heaters >40 mmBtu/hr because NOx control technologies such as SCR, LoTOx, Great Southern Flameless heaters are either commercially available, achieved-in-practice and/or can be designed to achieve 2 ppmv NOx in a cost-effective manner.

Incremental Emission Reductions beyond 2005 BARCT level: 0.94 tons per day
Total Incremental Costs: $ 237 M
Average Incremental Cost Effectiveness: $28 K/ton (DCF) and $45 K/ton LCF)

Table B. 11 – Details of Cost Estimates for Boilers and Heaters

Summary of CE for Boilers/Heaters

Results:

Total units = 23 boilers + 189 heaters = 212 units

Cost-effective units = 82. Not cost-effective units = 130

Total SCRs = 75 (24 upgraded, 51 new)

Total PWVs = 237 millions. Total emission reductions = 0.94 tpd.

Average cost effectiveness = 27,710 $/ton DCF = 45 K $/ton LCF

	Fac ID	Device ID	Device	Process Name	Max Rating for Boilers Heaters (mmbtu/hr)	2011 Emissions (tpd)	Emission Reductions Beyond 2005 BARCT (tpd)	PWV for 2 ppmv SCR = 1.1 * PWV of 5 ppmv SCR ($ M)	PWV for 5 ppmv SCR ($ M)	Increment costs ($ M)	Increment CE ($/ton)	Existing Control and Year	Existing NOx at 3% O2
1	6	925	HEATER	H2 PRODUCTION	931	0.06	0.03	49.50	45.00	4.50	19,066	SCR 87	5.65
2	5	3530	HEATER	H2 PRODUCTION	653	0.02	0.02	49.50	45.00	4.50	30,425	SCR 00	2.69
3	1	570	HEATER	H2 PRODUCTION	650	0.10	0.02	49.50	45.00	4.50	20,782	SCR 85, LNB 6	12.66
4	1	27	HEATER	CRUDE	550	0.13	0.02	33.00	30.00	3.00	17,671	LNB 97	21.18
5	6	913	HEATER	CRUDE	457	0.09	0.01	33.00	30.00	3.00	21,995	SCR 92	13.68
6	1	1465	HEATER	H2 PRODUCTION	427	0.03	0.01	33.00	30.00	3.00	24,476	SCR, LNB 95	7.25
7	5	641	HEATER	HYDROCRACKING	365	0.18	0.02	22.00	20.00	2.00	13,703	LNB 99	27.69
8	8	429	BOILER	STEAM GEN/SCR09	352	0.03	0.01	22.00	20.00	2.00	25,992	SCR 2009	6.00
9	8	430	BOILER 11	STEAM GEN	352	0.16	0.01	22.00	20.00	2.00	27,891		
10	8	59	HEATER	CRUDE	350	0.19	0.01	22.00	20.00	2.00	16,363		
11	7	220	HEATER	H2 PRODUCTION	350	0.08	0.01	22.00	20.00	2.00	22,064	SCR 1990	21.66
12	5	2216	BOILER	STEAM GEN	342	0.11	0.01	22.00	20.00	2.00	22,257	SCR 88	47.16
13	6	1236	BOILER	STEAM GEN	340	0.01	0.01	22.00	20.00	2.00	23,944	SCR 97	6.76
14	8	210	HEATER	H2 PRODUCTION	340	0.19	0.01	22.00	20.00	2.00	25,457		
15	6	1239	BOILER	STEAM GEN	340	0.02	0.01	22.00	20.00	2.00	27,239	SCR 97	7.75
16	5	82	HEATER	CRUDE	315	0.02	0.01	22.00	20.00	2.00	18,018	SCR 91	5.69
17	5	83	HEATER	CRUDE	315	0.02	0.01	22.00	20.00	2.00	19,885	SCR 91	5.69
18	1	535	HEATER	CAT REFORM	310	0.07	0.01	22.00	20.00	2.00	27,440	LNB 94	22.84
19	6	803	BOILER	STEAM GEN	309	0.21	0.01	22.00	20.00	2.00	41,496	LNB 86	104.00
20	7	686	BOILER 7	STEAM GEN	304	0.02	0.01	22.00	20.00	2.00	31,442	SCR 2009	8.50
21	1	63	HEATER	CRUDE	300	0.01	0.01	22.00	20.00	2.00	24,097	SCR, LNB 94	4.81
22	6	805	BOILER	STEAM GEN	291	0.19	0.01	22.00	20.00	2.00	42,085	LNB 88	74.91
23	1	532	HEATER	CAT REFORM	255	0.04	0.01	22.00	20.00	2.00	34,138	LNB 01	16.64
24	7	688	BOILER 6	STEAM GEN	250	0.17	0.01	22.00	20.00	2.00	42,403		
25	9	1550	BOILER/new SCR	STEAM GEN	245	0.02	0.01	22.00	20.00	2.00	26,507	SCR 2008	5.39
26	5	643	HEATER	HYDROCRACKING	220	0.04	0.01	22.00	20.00	2.00	31,409	LNB 99	19.63
27	5	84	HEATER	CRUDE	219	0.02	0.01	22.00	20.00	2.00	23,986	SCR 91	5.69
28	5	20	HEATER	CRUDE	217	0.06	0.01	22.00	20.00	2.00	31,482	LNB 01	23.16
29	9	430	HEATER	HYDROTREATING	200	0.02	0.01	11.00	10.00	1.00	12,602	SCR	8.43
30	4	9	HEATER	CRUDE	199	0.10	0.01	11.00	10.00	1.00	14,133	SCR	31.91 - 41.32
31	5	3031	HEATER	CAT REFORM	199	0.00	0.01	0.00	0.00	0.00	0	SCR 94	1.64

	Fac ID	Device ID	Device	Process Name	Max Rating for Boilers Heaters (mmbtu/hr)	2011 Emissions (tpd)	Emission Reductions Beyond 2005 BARCT (tpd)	PWV for 2 ppmv SCR = 1.1 * PWV of 5 ppmv SCR ($ M)	PWV for 5 ppmv SCR ($ M)	Increment costs ($ M)	Increment CE ($/ton)	Existing Control and Year	Existing NOx at 3% O2
32	7	687	BOILER 8	STEAM GEN	179	0.09	0.00	11.00	10.00	1.00	25,410		
33	5	471	HEATER	CAT REFORM	177	0.00	0.00	0.00	0.00	0.00	0	SCR 94	1.64
34	5	161	HEATER	COKING	176	0.06	0.01	11.00	10.00	1.00	18,504	SCR 92	2.71
35	5	159	HEATER	COKING	176	0.05	0.01	11.00	10.00	1.00	18,504	SCR 92	2.71
36	5	160	HEATER	COKING	176	0.05	0.01	11.00	10.00	1.00	20,355	SCR 92	2.71
37	8	104	HEATER	COKING	175	0.05	0.00	11.00	10.00	1.00	22,645		
38	8	105	HEATER	COKING	175	0.05	0.00	11.00	10.00	1.00	24,004		
39	6	914	HEATER	CRUDE	161	0.04	0.01	11.00	10.00	1.00	17,704	SCR 92	13.70
40	8	78	HEATER	CRUDE	154	0.04	0.01	11.00	10.00	1.00	21,401		
41	8	79	HEATER	CRUDE	154	0.04	0.00	11.00	10.00	1.00	23,180		
42	1	29	HEATER	CRUDE	150	0.05	0.00	11.00	10.00	1.00	26,662	LNB 94	35.74
43	4	388	HEATER	HYDROCRACKING	147	0.12	0.01	11.00	10.00	1.00	20,879	SCR	49.6 - 73.5
44	4	1122	BOILER	H2 PRODUCTION	140	0.01	0.00	11.00	10.00	1.00	26,106	SCR	7.7 - 8.1
45	9	6	HEATER	CRUDE	136	0.04	0.01	11.00	10.00	1.00	21,766		19.31
46	7	264	HEATER	HYDROCRACKING	135	0.05	0.00	11.00	10.00	1.00	35,517		
47	1	155	HEATER	COKING	130	0.05	0.00	11.00	10.00	1.00	33,211	LNB 00	39.55
48	1	31	HEATER	CRUDE	130	0.04	0.00	11.00	10.00	1.00	35,015	LEA 01	29.21
49	1	153	HEATER	COKING	130	0.04	0.00	11.00	10.00	1.00	36,700	LNB 97	36.14
50	1	151	HEATER	COKING	130	0.04	0.00	11.00	10.00	1.00	37,286	LNB 97	39.39
51	6	930	HEATER	HYDROCRACKING	129	0.06	0.00	11.00	10.00	1.00	36,151	ULNB 95	55.12
52	9	378	BOILER	STEAM GEN	128	0.01	0.01	11.00	10.00	1.00	20,725	SCR	5.17
53	6	120	HEATER	COKING	126	0.05	0.00	11.00	10.00	1.00	38,824	LNB 95	51.79
54	5	472	HEATER	CAT REFORM	125	0.00	0.00	0.00	0.00	0.00	0	SCR 94	1.64
55	1	67	HEATER	CRUDE	120	0.04	0.01	11.00	10.00	1.00	20,294	LNB 94	34.37
56	4	90	HEATER	FCCU	127	0.06	0.00	11.00	10.00	1.00	44,113	LNB	46.6 - 52.1
57	3	77	BOILER	STEAM GEN	112	0.05	0.00	11.00	10.00	1.00	44,197		
58	3	76	BOILER	STEAM GEN	112	0.05	0.00	11.00	10.00	1.00	44,197		
1	9	768	HEATER	HYDROTREATING	110	0.02	0.04	11.00			31,494	SCR	9.43
2	7	154	HEATER	CAT REFORM	110	0.13	0.03	11.00			41,628		
3	5	451	HEATER	HYDROTREATING	102	0.10	0.03	11.00			40,338	no control	99.31
4	1	33	HEATER	CRUDE	100	0.02	0.02	5.50			25,116	LNB 94	22.79
5	7	155	HEATER	CAT REFORM	100	0.04	0.01	5.50			47,328		
6	9	22	HEATER	COKING	95	0.02	0.02	5.50			29,430		20.33
7	4	89	HEATER	FCCU	95	0.05	0.08	5.50			7,718	LNB	46.6 - 52.1
8	6	269	HEATER	HYDROTREATING	94	0.03	0.01	5.50			44,210	LNB 88	34.10
9	6	918	HEATER	COKING	91	0.08	0.02	5.50			34,411	LNB 91	91.70
10	6	917	HEATER	COKING	91	0.07	0.02	5.50			38,067	LNB 98	82.07
11	1	250	HEATER	FCCU	89	0.02	0.02	5.50			32,240	LNB 95	27.87
12	5	473	HEATER	CAT REFORM	88	0.00	0.02	0.00			0	SCR 94	1.64

	Fac ID	Device ID	Device	Process Name	Max Rating for Boilers Heaters (mmbtu/hr)	2011 Emissions (tpd)	Emission Reductions Beyond 2005 BARCT (tpd)	PWV for 2 ppmv SCR = 1.1 * PWV of 5 ppmv SCR ($ M)	PWV for 5 ppmv SCR ($ M)	Increment costs ($ M)	Increment CE ($/ton)	Existing Control and Year	Existing NOx at 3% O2
13	7	146	HEATER	HYDROTREATING	76	0.02	0.01	5.50			43,097		
14	6	85	HEATER	COKING	74	0.06	0.01	5.50			45,265	LNB 88	97.00
15	8	174	HEATER	HYDROTREATING	70	0.06	0.02	5.50			35,422		
16	9	53	HEATER	HYDROTREATING	68	0.01	0.02	5.50			32,565		16.43
17	6	84	HEATER	COKING	67	0.04	0.01	5.50			44,780	LNB 85	116.81
18	6	83	HEATER	COKING	67	0.05	0.01	5.50			45,124	LNB 88	103.95
19	4	770	HEATER	HYDROTREATING	63	0.00	0.02	5.50			32,156	SCR	5.5 - 6.4
20	5	625	HEATER	HYDROCRACKING	63	0.06	0.01	5.50			47,614	no control	90.40
21	7	194	HEATER	HYDROTREATING	60	0.05	0.02	5.50			39,909		
22	4	218	HEATER	CAT REFORM	60	0.02	0.01	5.50			40,392	LNB	29.8 - 32.2
23	5	619	HEATER	HYDROCRACKING	57	0.05	0.01	5.50			45,968	no control	95.47
24	5	617	HEATER	HYDROCRACKING	57	0.05	0.01	5.50			40,839	no control	84.24

<u>Summary</u>

	tpd		
>110	0.44		93.50
40-110	0.495	143.00	
Total Units	0.94		
Total costs		237	
Average CE	27,710		

References for Boilers and Heaters

1. Staff Report of Proposed Amendments to SOx RECLAIM. Agenda 37 of the SCAQMD Governing Board Meeting. November 5, 2010.

2. EPA Air Pollution Cost Manual, Section 4 – NOx Controls, EPA/452/B-02-001, Sixth Edition, January 2002.

3. Reducing NOx and NH3 Emissions with Advanced SCR Technology. Rita Aiello, Kevin Doura, Mike Baran, Wilson Chu, Paul Anderson, Johnson Matthey. Paper #33233. A&WMA's 107th Annual Conference & Exhibition, June 24-27, 2014, Long Beach California.

4. UltraCat Catalytic Filters Remove PM, SO_2, HCl, NOx, Dioxins and HAPs. NOx Control as Low as 350 degrees F – TriMer's brochure – www.tri-mer.com.

5. Combating NOx from Refinery Sources Using SCR. Haldor Topsoe. Presentation at the 2nd Annual World Refining Technology Summit & Exhibition, 2010, Abu Dhabi. www.topsoe.com, posted online and downloaded in January 2014.

6. Information posted online at the website for Mitsubishi and Cormetech, www.cormetech.com/non-reductionh.htm, and www.mhpowersystems.com/scr.html, downloaded on January 2014.

7. SCR and Zero-Slip TM Technology. T.W. Hastings of Cormetech, Inc. and A. Hattori of Mitsubishi Power Systems, Inc. Presentation of June 17, 2003 Turbo Expo – Atlanta, GA.

8. Dual Function Catalyst Promises High NOx Removal with Zero Ammonia Slip for Gas Turbine Applications. J.A. Rosin and H.S. Rosenberg. Power Engineering, September 2001, Vol. 105, Issue 9, page 76.

9. Optimization of Ammonia Source for SCR Applications. R. Salib and R. Keeth of Washington Group International. Paper Poster Session No. 46. (no date)

10. Comparison of Urea Based Ammonia to Liquid Ammonia Systems for NOx Reduction Applications. J. E. Fisher, WAHLCO, Inc.

11. Comparison of Urea, 19% Aqueous Ammonia, and Anhydrous Ammonia Operating Costs, Canyon Energy Project. D. Kirk of Fuel Tech Inc. to C. McFarlin of California Energy Commission, September 3, 2008.

12. Influence Factors and Control Research on Ammonium Bisulfate Formation in the Process of Selective Catalytic Reduction. S. Ma et.al., North China Electric Power University. Journal of the Air & Waste Manuscript Paper UAWM-2013.

13. SCR Costs Data Provided to SCAQMD staff – Refinery Survey. June 2013

14. SCR Costs Information from a Refinery Consultant's Study. Refinery meeting with the SCAQMD staff. February 21, 2013.

15. SCR Costs Information from Manufacturer A. E-mail to Minh Pham on May 5, 2014.

16. SCR Costs Information from Manufacturer B. E-mails to Minh Pham on May 8 and May 14, 2014.

17. SCR Costs Information from Manufacturer C. E-mails to Minh Pham on May 8 and May 14, 2014.

18. The World's First Flameless Crude Heater. William C. Gibson, Marianne Zimola. Paper #32895. A&WMA's 107th Annual Conference & Exhibition, June 24-27, 2014, Long Beach California.

19. Oxy-Flameless Combustion for Refinery Process Heaters. William C. Gibson, Marianne Zimola. Paper #32899. A&WMA's 107th Annual Conference & Exhibition, June 24-27, 2014, Long Beach California.

20. Information for Great Southern Flameless. E-mails from Bill Gibson and Marianne Zimola to Minh Pham. November 2013 and July 2014.

21. Costs Information for Great Southern Flameless Heaters and Oxy-Fuel Flameless Heaters. E-mails from Marianne Zimola to Minh Pham, July 18-30, 2014.

22. ClearSign Demonstrates Sub 5 ppmv NOx and CO without SCR, FGR, or High Excess Air. Joseph Colannino. Paper #33165. A&WMA's 107th Annual Conference & Exhibition, June 24-27, 2014, Long Beach California.

23. Costs Information from ClearSign. E-mails from Roberto Ruiz to Minh Pham. July 24-29, 2014.

24. BARCT Analysis for SCAQMD NOx RECLAIM, Non-Confidential Report, Norton Engineering Consultants, November 26, 2014. (See Addendum 1)

Appendix C – Refinery Gas Turbines

Process Description

Gas turbines are used in refineries to produce both electricity and steam. Frame gas turbines are exclusively used for power generation and continuous base load operation ranging up to 250 MW with simple-cycle efficiencies of approximately 40% and combined-cycle efficiencies of 60%. Aero-derivative gas turbines are adapted from aircraft engines. These turbines are lightweight and more efficient than frame turbines however the largest units are available for up to only 40-50 MW. The existing gas turbines at the refineries in the SCAQMD range from 7 MW to 83 MW. Most are all operated with duct burners, heat recovery steam generator (HRSG), Selective Catalytic Reduction (SCR), CO catalysts and some units have Ammonia Slip Catalysts (ASC), Cheng Low NOx (CLN), and Dry Low NOx (DLN) or Dry Low Emissions (DLE) combustors. Figure C.1 shows a typical layout of a turbine, duct burner, HRSG, and control system.

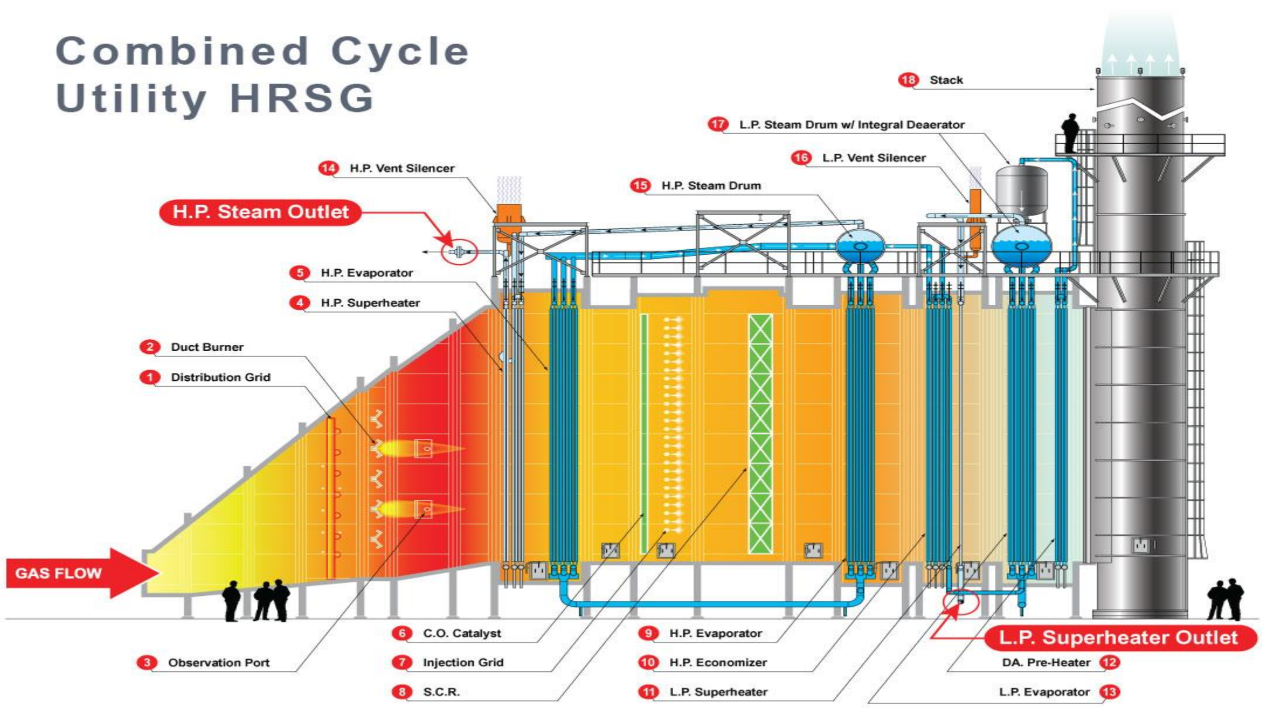


Figure C. 1 - Gas Turbine with Duct Burner (victoryenergy.com)

Emission Inventory

There are a total of 21 gas turbines/duct burners classified as major NOx sources at the refineries in the SCAQMD. Collectively, the 21 gas turbines/duct burners emitted about 1.33 tons per day in 2011 as shown in Table C.1. Table C.1 also includes information on the type and size of equipment, what controls are in place, and the year the controls were installed. NOx levels at the stack vary from 1.67 ppmv at 15% O2 for units with SCR and ASC to 5.95 ppmv for units with SCR and water injection. [1]

It should be noted that at the inception of the RECLAIM program, the SCAQMD staff provided allocations for the gas turbines based on the 2000 BARCT level of 62.27 lbs/mmscft. If all gas turbines/duct burners were operated at the 2000 BARCT level of 62.27 lb/mmscft, the emissions from these turbines would amount to about 4.86 tons per day. In addition, these units are subject to either BACT limits or permit conditions that limit the annual mass emissions at the time the permits were issued: Refinery 1's gas turbines/duct burners have a BACT limit of 8 ppmv NOx; Refinery 5, 6 and 7's units have a BACT limit of 9 ppmv; and units at Refinery 4 are subject to a limit of 583 tons per year of NOx emissions. If these gas turbines/duct burners were operated at the BACT levels or at the levels specified in the permit conditions at the time the permits were issued, the emissions would be 5.99 tons per day, higher than 4.86 tons per day of the 2000 BARCT. All of the gas turbines are currently emitting at a level below their allocations and below the levels at the time their permits were issued. Technology improvements with time and the implementation of BACT levels have recently changed emissions to 2 ppmv for frame turbines and 2.5 ppmv for aero-derivative units.

Achieved-In-Practice NOx Levels for Gas Turbines

- Refinery 10's 7 MW aero-derivative gas turbine/duct burner with Cormetech SCR and ASC operating under a permit condition of 2.5 ppmv NOx, 15% O_2 has actually achieved the levels below 2 ppmv NOx at 15% O_2. [1, 6, 9, 25]

- In 2010, Refinery 5 received a permit to construct a new 46 MW frame gas turbine/duct burner with DLN, SCR and CO catalysts. The permit has a limit of 2 ppmv NOx, 15% O_2 and 5 ppmv NH3 slip. This unit has been in operation since 2012. [28-29]

- In 2011, Refinery 1 received a permit to construct for a 85 MW gas turbine /duct burner with DLN, SCR and CO catalyst. The permit condition required the turbine to be operated at a BACT level of 2 ppmv NOx, 15% O2. Regardless of the permit, Refinery 1 did not install the gas turbine. [7]

The above 7 MW aero-derivative, 46 MW and 85 MW frame gas turbines/duct burners demonstrate the feasibility of the proposed level of 2 ppmv NOx, 15% O2, annual average, for gas turbines using natural gas as well as refinery gas. The limits stated in the permit conditions are based on short-term averages (e.g. 1-hour average), which is more stringent than the proposed BARCT at 2 ppmv, annual average.

Table C. 1 - 2011 Emissions for Refinery Gas Turbines/Duct Burners

Fac ID	Device ID	Device	mmBtu/hr	MW	Turbine Type	2011 Emissions (lbs)	Control & Year	Existing ppmv NOx at 15% O2
1	1226	Turbine	986	83	GE	78,418	DLE, SCR, CO, 88	2.80
1	1227	Duct Burner	340			27,097	SCR, CO, 88	2.80
1	1233	Turbine	986	83	GE	69,996	SCR, CO 98	3.50
1	1234	Duct Burner	340			22,034	SCR, CO 98	3.50
1	1236	Turbine	986	83	GE	72,933	SCR, CO, 88	2.53
1	1237	Duct Burner	340			21,090	SCR, CO, 88	2.53
1	1239	Turbine	986	83	GE	85,228	SCR, CO, 88	2.52
1	1240	Duct Burner	340			15,262	SCR, CO, 88	2.52
6	926	Turbine	316	23	GE	110,546	SCR, 87	5.65
4	810	Turbine	392	30	Pratt Whitney	55,264	SCR, CO, WI	5.95
4	812	Turbine	392	30	Pratt Whitney	50,084	SCR, CO, WI	4.82
7	828	Turbine	646	59	Westinghouse	118,842	SCR, 86	5.65
7	829	Duct Burner	99			16,191	SCR, 86	5.65
5	2198	Turbine A	560	46	GE Frame6	73,759	SCR, 95	4.20
5	2199	Duct Burner	120			7,521	SCR, 95	4.20
5	2207	Turbine B	560	46	GE Frame6	61,809	SCR, 95	3.46
5	2208	Duct Burner	120			9,569	SCR, 95	3.46
5	3053	Turbine C	506	46	GE Frame6	68,408	SCR, 96	4.24
5	3054	Duct Burner	286			5,686	SCR, 96	4.24
10	677	Turbine	90	7	Solar, Taurus	1,598	SCR, ASC, 03	1.67
10	679	Duct Burner	50		Solar, Taurus	430	SCR, ASC, 03	1.67
					Total (tpd)	**1.33**		

Control Technology

Gas turbines/duct burners are capable of emitting very low NOx emission levels. Currently most of the units at the refineries in SCAQMD are emitting less than 5 ppmv NOx using commercially available control technologies such as water or steam injection, DLN, DLE, CLN, SCR, CO catalysts and ASC.

Water or Steam Injection

Most of the NOx generated in the gas turbine/duct burner is "thermal" NOx. Water or steam injected into the high temperature frame zone quench the temperature down and reduce NOx to approximately 25 ppmv at 15% O2. However, water/steam injection tends to increase the CO emissions appreciably.

Dry Low NOx (DLN) and Dry Low Emissions (DLE)

DLN/DLE is based on a concept of lean premixed combustion – gaseous fuel is premixed with combustion air at the air to fuel ratio two times higher than the stoichiometric ratio. The lean mixture reduces peak flame temperature in the combustion zone and suppresses "thermal" NOx formation. The premixing chamber for the combustion air and gaseous fuel must be specifically designed for each type of turbines and integrated into the turbine design. Every 4 to 5 years, the combustion liners of the DLE/DLN combustors are deteriorated and must be replaced. Table C.2 shows potential performance of DLN/DLE in certain models of GE frame and aero-derivative turbines. A few models of natural-gas-fired turbines can reach as low as 3-5 ppmv NOx. Maintaining the low NOx emission levels from the turbines from full to low load, or from turbines with varying load swings coupled with the emissions from the duct burners remain a challenge for DLN/DLE combustor technology. Most manufacturers would guarantee a level of 15-25 ppmv for DLE/DLN combustors. [14-16]

Table C. 2 – Performance of DLN and DLE

Combustion System	Frame Type	Potential NOx Level
DLN1	GE 3/5/6B/7/9E	9-25 ppmv
DLN1	GE 6B/7E/9E	3-5 ppmv
DLN2.6	GE 6F/7F	9 ppmv
DLN2.6	GE 9F	9 ppmv
Combustion System	**Aero-derivative Type**	**Potential NOx Level**
DLE	GE LMS100 (100 MW)	25 ppmv (gaseous fuel)
DLE	GE LM6000 (40-55 MW)	15-25 ppmv (gaseous fuel) 100 ppmv (liquid fuel)
DLE	GE LM2500 (28 – 34MW)	15-25 ppmv (gaseous fuel) 100 ppmv (liquid fuel)

Cheng Low NOx (CLN)

Cheng Low NOx is an alternative to DLN/DLE. [17-23] In lieu of premixing air to fuel, CLN premixes steam with fuel prior to combustion. The difference in the CLN and the traditional steam injection technology is that CLN can deliver a uniform homogenous mix of steam and fuel to the combustion chamber. A schematic diagram for the CLN is shown in Figure C.2.

The effect of homogeneity on CO and NOx emissions is shown in Figure C.3. With careful mixing, the steam to fuel ratio can be extended to 4 to 1 without causing any flameout and increasing CO emissions. The NOx level can theoretically be lowered to 1 ppmv without the use of SCR. The CO level can be reduced to below 2 ppmv without the use of CO catalyst. [17-20]

The CLN technology was developed by Cheng Power Systems, Inc. It was patented in 2002. Since 2005, the CLN technology has been running continuously on a 6 MW Allison Rolls Royce (RR) KB5S at the Stanford Research Institute (SRI) in Menlo Park. In 2009, it was demonstrated on a GE LM2500 at Calpine Corporation's Agnews Cogeneration Plant. The newest CLN was installed in the GE LM2500PH gas turbine. Table C.3 below shows a list of CLN installations in the past decade.

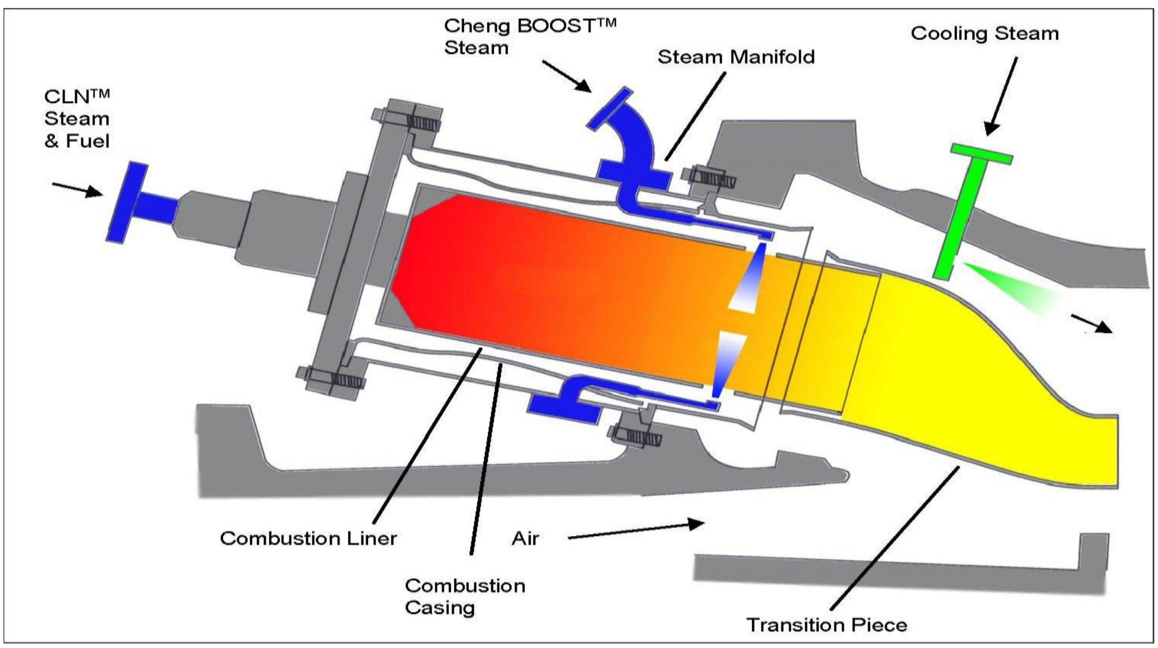


Figure C. 2 - Cheng Low NOx (Reference 22)

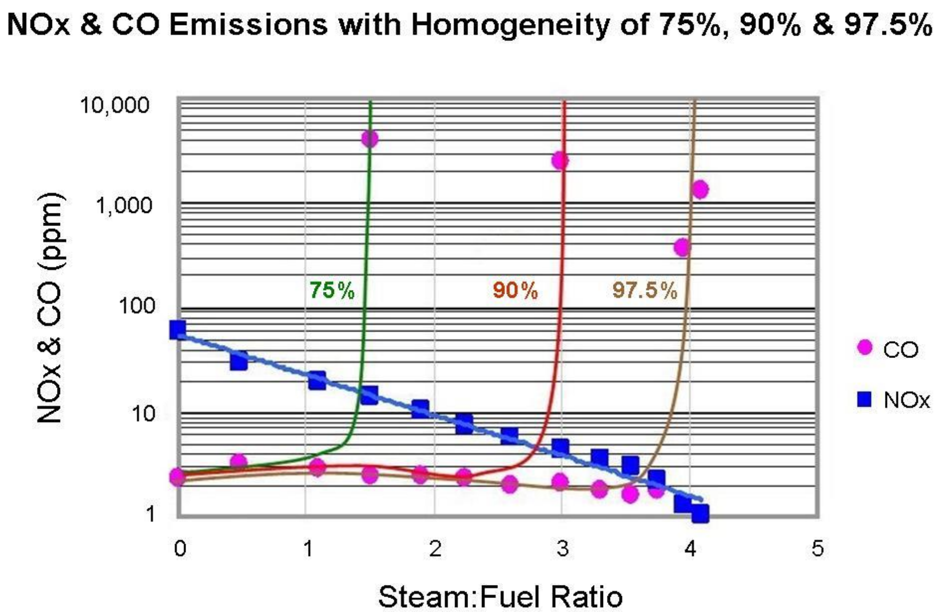


Figure C. 3 - Effect of Homogeneity and Steam to Fuel Ratio in CLN Application (Reference 22)

Table C. 3 – Installations of CLN

Engine	Rated Power, MW
RR 501 KH	6.2
RR 501 KB7S	5.2
RR 501 KB5	3.9
RR Avon 1535	15
GE LM2500	22
GE 6B	39.5
LM 6000 PC	43
GE 7EA	85

Figure C.4 below shows some of the test results of CLN. Additional test results can be found in References 18-20. It should be noted that, CLN was put in operation on two GE Frame 6B turbines at a refinery in the SCAQMD. Actual test data at the refinery site in the SCAQMD shows a level of 17.7 ppmv NOx at 15% O2 at the steam to fuel ratio of 1.5. [18-19] In addition to lowering NOx and CO emissions, additional benefits that CLN provide are lowering the heat rate and increasing power output.

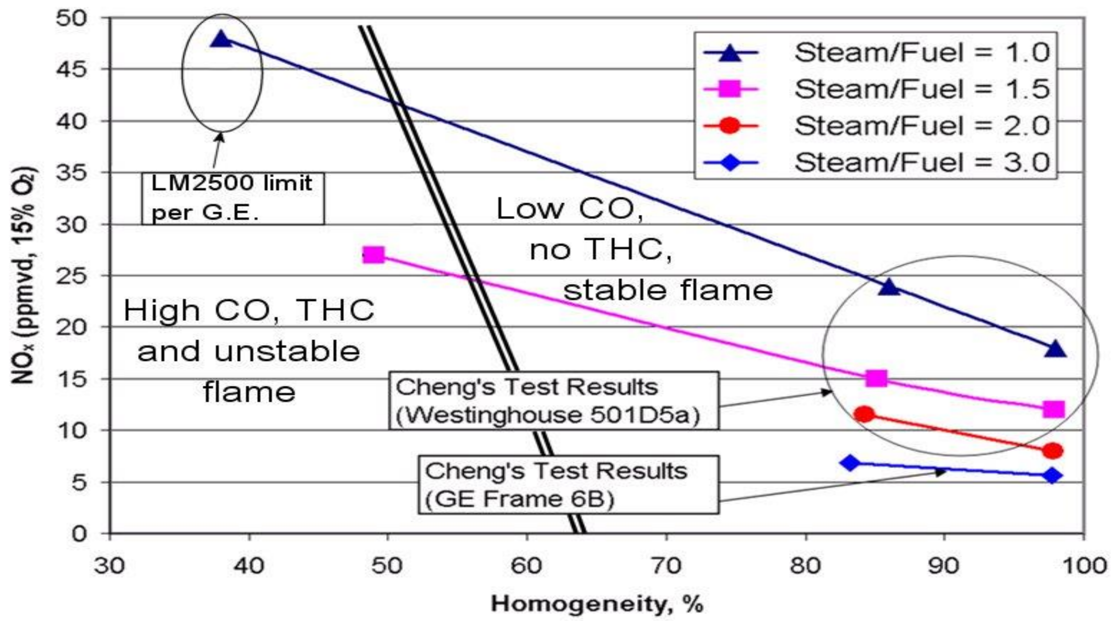


Figure C. 4 - Effect of Homogeneity and Steam to Fuel Ratio on NOx Emissions in CLN Application

In summary, CLN with a steam to fuel ratio of 1.75 to 1 is proven viable to reduce NOx emissions to 9 ppmv or 15 ppmv. SCR can be used in combination with CLN to reach 2 ppmv NOx and CO levels. The current CLN system comes with automatic adjustment software to continuously monitor and optimize the amount of steam to fuel ratio. Cheng Power projects that with a steam to fuel ratio of 3 or 4 to 1, CLN would be able to reach 2 ppmv NOx without the use of SCR.[21-23]

Selective Catalytic Reduction

SCR is an effective control technology for NOx which uses ammonia (NH_3) to selectively reduce NOx to nitrogen. Please refer to Appendix A for further descriptions.

All SCR manufacturers that staff contacted confirm that SCRs can be designed to reduce 95%-98% NOx emissions when used in combination with DLE/DLN, CLN, CO catalysts, ASC, or water/steam injection. Two ppmv NOx can be achieved while maintaining low ammonia slips of less than 5 ppmv.

Cormetech indicated that they have achieved less than 2 ppmv NOx and 2 ppmv NH_3 in 10 gas turbines. In addition one of the full scale demonstration projects is a 7 MW cogeneration unit located at a refinery in the Los Angeles Basin (startup in 2003) that achieved <2 ppmv NOx at <0.1 ppmv ammonia slip. [25] BASF advertised that their vanadia/titania catalysts have 99% NOx removal efficiency in the optimum temperature range of 550 – 800 degrees F, and their zeolite catalysts have 99% removal efficiency in the optimum temperature range of 675 - 1075 degrees F, and they also supply ASC that can reduce both ammonia and NOx. [27]

The CO catalysts are used in conjunction with SCR catalysts to concurrently reduce NOx to nitrogen and oxidize CO and hydrocarbon to CO2 and water. The CO catalysts are typically made of platinum, palladium or rhodium, and have about 90% removal efficiency for CO and remove 85% to 90% of hydrocarbon or hazardous air pollutants.

Costs and Cost Effectiveness

It has been reported that the costs of SCR catalysts have dropped significantly over time – catalyst innovations have been the principle driver, resulting in a 20 percent reduction in catalyst volume and costs with no change in performance. [10] Staff developed a cost curve that plots the PWV of the control devices as a function of gas turbines' maximum rating utilizing the following sets of data:

- Refinery data
- EPA and DOE data
- Data provided by SCR manufacturers and Cheng Low NOx

Staff then used the PWVs from the cost curve to estimate the cost and cost effectiveness for all 21 turbines/duct burners at the refineries. The details are explained below.

Refinery 1's Cost Information for SCR

In 2011, Refinery 1 received a permit to construct for an 85 MW gas turbine/duct burner. It was planned as the fifth cogeneration unit at this site. SCR and CO catalysts were proposed to control NOx and CO emissions from a DLN combustor. The total installed costs for SCR and CO provided in their application for permit was estimated to be $5.9 million. Staff used a Marshall Index factor of 1.2 to adjust to current dollars. [7]

This refinery has four existing cogeneration units at the site emitting between 2.52 ppmv to 3.50 ppmv NOx. The refinery reported through a survey conducted in 2013 that the annual operating costs were $375,000 per year, and catalyst replacement costs were $950,000 every 10 years. [8]

Using Equation 1 below with a Marshall Index adjustment factor of 1.2 to bring the costs to present dollars, staff estimated the PWV for the SCR/CO catalysts were approximately $15.50 million.

PWV = Adjustment Factor x (TIC + (15.62 x AC) + (1.14 x CR)) (Equation 1)

Where:

PWV = Present Worth Value, $
TIC = Total Installed Costs, $
AC = Annual Operating Costs, $
CR = Catalyst Replacement Costs, $

Refinery 10's Cost Information for SCR

This refinery has a 7 MW cogeneration unit that is using SCR and ASC (installed in 2002) to achieve a level of 1.67 ppmv NOx at 15% O2. The refinery reported total installed costs, annual operating costs, and catalyst replacement costs every 10 years. Using Equation 1 with Marshall Index of 1.4, staff estimated the PWV for SCR/ASC catalysts of approximately $3.8 million. [6, 9]

Costs Information from SCR Manufacturers

All SCR manufacturers that staff contacted confirmed that it is feasible to achieve 2 ppmv NOx at 5 ppmv ammonia slip for natural gas as well as refinery gas applications using SCRs, or combinations of SCRs with CO, or ammonia slip catalysts.

Manufacturer B provided the cost to add catalyst and increase the ammonia usage to the SCR of Refinery 1 to achieve 2 ppmv NOx. In this conservative estimate, Manufacturer B assumed that the existing NOx levels were at 10 ppmv. Manufacturer B believed that with the current SCR system at Refinery 1, the refinery could meet 2 ppmv NOx just by adding ammonia. [5]

Additional catalysts = $234,000 ($250 per cubic foot)
Additional ammonia = $11,000 based on $900 per ton ammonia

Manufacturer A provided several sets of cost information for 1) conventional SCRs and for 2) an advanced SCR with ASC for 83 MW and 7 MW cogeneration units with inlet NOx concentrations at 35 ppmv and 50 ppmv to get to 2 ppmv and 5 ppmv outlet NOx concentrations. The costs are summarized in Table C.4 below: [4]

Table C. 4 – Costs of SCR and ASC for 83 MW and 7 MW Cogeneration Units

Engine	Rated Power 83 MW	Rated Power 83 MW	Rated Power 83 MW	Rated Power 7 MW
Exhaust Flow, lb/hr	2,653,000	2,653,000	2,653,000	140,000
Exhaust Temp, ºF	625	625	625	625
SCR + CO Catalysts				
NOx in, ppmv	35	50	35	50
NOx out, ppmv	2	2	8 (note)	2
CO Conversion, %	67	67	67	90
NH3 Slip, ppmv	5	5	5	5
Costs, $	1,333,000	1,380,000	1,050,000	$75,000
SCR + Ammonia Slip Catalysts				
NOx in, ppmv	35	50	35	50
NOx out, ppmv	2	2	8	2
CO Conversion, %	92	92	67	92
NH3 Slip, ppmv	5	5	5	5
Costs	$986,000	$1,100,000	$650,000	$60,000

Note: 8 ppmv NOx is the existing permit condition of Refinery 1's cogeneration unit.

The SCR, CO and ASC have a catalyst replacement frequency of 10 years. Manufacturer B assumed that the existing ammonia storage tanks and injection systems can be used. Associated equipment such as pumps, control valves and vaporizer capacity may increase costs however, this equipment was not included in the cost estimate. Installation and duct modifications were also not included in the cost estimate. Staff used a multiplier factor of 1.6 to add the costs of modifications and installation based on Refinery 10 data. Assuming the entire existing SCR and CO catalysts were replaced with SCR and ASC using the costs provided by Manufacturer B, staff estimated the SCR/ASC's PWVs would be approximately of $19 million for the 83 MW turbine and $2 million for the 7 MW turbine.

SCR Cost Information in Literature

Reference 2 contains extensive cost information for SCR catalysts to achieve 80% - 90% reduction from various inlet concentrations to 9 ppmv NOx outlet concentration. The gas turbines in the SCAQMD currently have inlet NOx concentrations in the range of 6 to 2.5 ppmv. An incremental reduction of 80% - 90% is needed to reach 2 ppmv NOx. Staff assumed that the entire SCR costs in Reference 2 can be used to estimate the "incremental" costs for the SCRs at the refineries to reach 2 ppmv. The estimated PWVs based on Reference 2 are $4.13 million for an SCR for a 7 MW turbine, and $22.44 million for an SCR for a 83 MW turbine.

Reference 3 contains the total installed costs and annual operating costs for conventional SCR to reach 79% NOx removal efficiency for a 4.2 MW, 23 MW and 161 MW turbines. Staff assumed that these costs can be used to reflect the "incremental" costs for the scenarios in the SCAQMD. Staff's estimate of the incremental PWVs for SCRs would be $4 million for the 4.2 MW gas turbine, $11 million for the 23 MW gas turbines, and $41 million for the 161 MW gas turbines.

Costs for Cheng Low NOx

Cheng Power Systems provided the following information on costs for CLN to meet 2 ppmv NOx.[20-21] In a presentation to the SCAQMD staff, Cheng compared the costs to operate a simple cycle 85 MW gas turbine with a Cheng cycle gas turbine to show that within a year of operation, the CLN would generate $9 million savings by reducing heat rate and increasing power, and that savings would offset the $5.5 million installation costs for the CLN.[21] The costs for Cheng Low NOx are listed in Tables C.5 and C.6.

Table C. 5 - Projected Income Gain Due to Power Increase for Cheng Low NOx

Engine	Power (MW)	Percent Power Increase
RR 501 KB series	5.2	20%
RR Avon 1535	15	20%
GE LM2500	22	20%
GE 6B	39.5	20%
LM 6000 PC	43	16%
GE 7EA	85	20%

Note: For GE 6B, the increase in power during summer was from 34 MW to 42MW.

Table C. 6 - Equipment and Installation Costs for Cheng Low NOx for Various Types of Gas Turbines

Engine	Power (MW)	Hardware	Installation/Software	Total
RR 501 KB series	5.2	$250,000	$125,000	$375,000
RR Avon 1535	15	$500,000	$350,000	$850,000
GE LM2500	22	$950,000	$650,000	$1,600,000
GE 6B	39.5	$1,700,000	$700,000	$2,400,000
LM 6000 PC	43	$1,800,000	$700,000	$2,500,000
GE 7EA	85	$3,000,000	$2,500,000	$5,500,000

Note: The above price assumes a CHP or Combined Cycle Plant with steam heat recovery system available. The extra costs of engine refurbishment or upgrade is to be determined based on a case by case basis and is not included in the above list.

Present Worth Values and Cost Effectiveness

Figure C.5 depicts a cost curve constructed relating the PWVs for the control devices as a function of turbine MW rating. The PWVs were then estimated for all gas turbines/duct burners to achieve 2 ppmv NOx with SCR/CO catalysts or SCR/ASC. See Table C.7. The PWVs with CLN/SCRs could be less if the savings resulting from increasing power would offset the CLN costs.

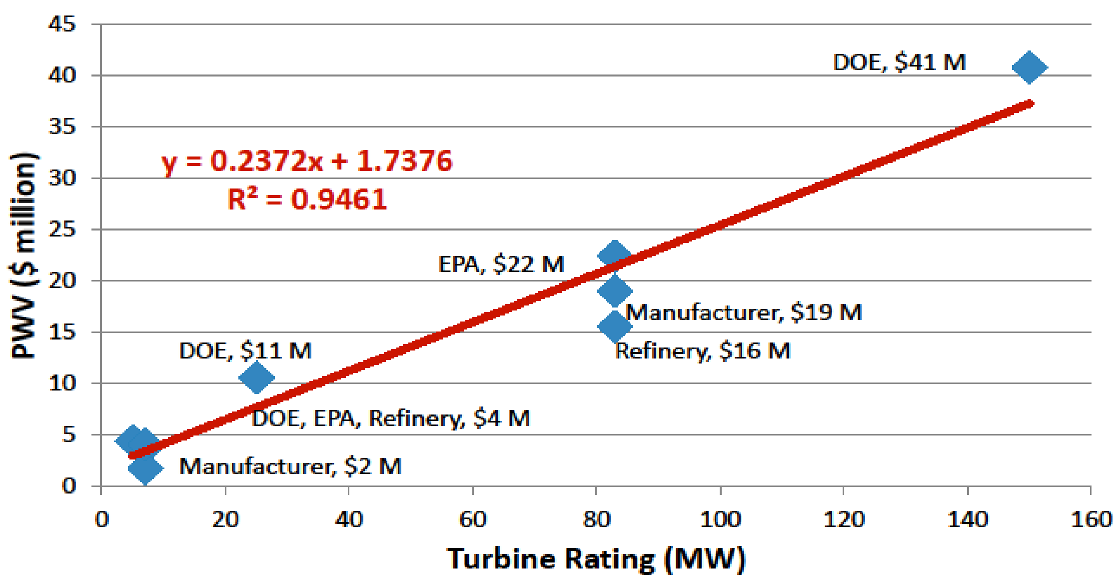


Figure C. 5 - Present Worth Values for Gas Turbines

Table C. 7 – Present Worth Values and Cost Effectiveness for Gas Turbines (December 2014)

No of Units	Rating (MW)	Current NOx Level (ppmv)	Incremental Emission Reduction per Unit from 2005 BARCT (tpd)	Staff's Estimate PWV per Unit ($M)	Incremental Cost Effectiveness ($/ton)
1	59	5.7	0.21	15.7 (new SCR)	8,210
3	46	3-4	0.31	12.6 (new SCR)	4,472
2	30	6	0.20	8.9 (new SCR)	4,851
1	23	5.7	0.14	7.2 (new SCR)	5,631
4	83	2.5-3.5	0.60	4.8 (add catalysts)	870
Total for all 10 units			**4.14**	**97.68**	

Incremental cost effectiveness values were estimated as follows based on the Discounted Cash Flow (DCF) method. A multiplication factor of 1.67 (to account for 25 years life of the SCR/CO/ASC system with frequency of catalyst replacement every 10 years) was used to convert the cost effectiveness estimated using DCF method to the Levelized Cash Flow (LCF) method:

CE = PWV / (ER x 365 days x 25 years)

Where:

CE = Incremental Cost Effectiveness, $/ton
PWV = Present Worth Value, $
ER = Incremental Emission Reductions, tpd

It should be noted that the cost estimates in Table C.7 above are conservative for several refineries as discussed below:

- Refinery 5's gas turbines A, B, and C currently emit 3.5 - 4.5 ppmv NOx at 15% O_2. Refinery 5 recently changed the catalysts used in Turbine A and Turbine B from Hitachi to Cormetech, and reduced the catalyst's volume from 2700 cubic feet to 667 cubic feet. The catalyst's volume of Turbine C is 950 cubic feet. The new Turbine D at Refinery 5 uses only 300 cubic feet of Cormetech catalysts to reach 2 ppmv NOx. Turbine D has DLN. Turbines A, B have CLN with steam injection at steam to fuel ratio of 1.5. Turbine C has steam injection at a steam to fuel ratio of 1.3. It should be noted that the steam to fuel ratio for Turbines A and B was permitted at 2.1 – 2.6. Refinery 5 has several options to reach 2 ppmv NOx: 1) add additional catalysts or change to more effective catalysts, 2) increase the steam to fuel ratio, or 3) retrofit with CLN or DLN. Increasing the steam to fuel ratio could add more power to the system and return the investments within a couple years of operation. [20, 28-29]

- Refinery 7 also changed the catalysts to Haldor Topsoe and Cormetech. With the use of more efficient SCR and ASC and additional ammonia, Refinery 7 may be able to reduce the catalyst volume and NOx emissions from 5 ppmv to 2 ppmv NOx without compromising the ammonia slip. [11, 25, 26, 31]

- Refinery 4's two 30 MW turbines currently use water injection, SCR and CO catalysts to achieve 5-6 ppmv NOx. The turbines have permit conditions limiting them to 96 ppmv NOx and 5 ppmv ammonia slip, and 583 tons per year NOx. Refinery 4 can retrofit the unit with steam injection or CLN technology, increase the power and reduce NOx without compromising the ammonia slip. Alternatively, the refinery may change to more effective SCR catalyst type and use ASC to reduce catalyst volume and increase NOx reduction effectiveness without compromising the ammonia slip. [11, 20, 25, 26]

- Refinery 10's gas turbine/duct burner is already at levels below 2 ppmv, thus no incremental costs were estimated for this refinery.

In conclusion, staff proposes to set a new BARCT level of 2 ppmv NOx for refinery gas turbines, aero-derivative as well as frame turbines, because NOx control technologies such as DLE/DLN, CLN, SCR with CO catalysts, SCR with ASC are commercially available and can be used together to achieve 2 ppmv NOx in a cost-effective manner. A level of 2 ppmv NOx is achieved-in-practice for an aero-derivative 7 MW gas turbine/duct burner using SCR and ASC. Two 46MW and 83 MW frame cogeneration units with SCR and CO catalysts were given permits to constructs since 2011 with permit conditions limiting to 2 ppmv NOx, 2 ppmv CO and 5 ppmv ammonia slip.

Consultant's Estimates for SCRs

NEC agreed with staff's proposal of 2 ppmv BARCT level for gas turbines using refinery gas. They proposed adding catalyst to the existing SCRs of the gas turbines to achieve 2 ppmv NOx. Their estimates are generally lower than the staff estimate since they assumed that more catalyst would be used rather than the addition of new SCRs. NEC's estimates are compared to the staff estimate in Table C.8. [33]

Table C. 8 - Comparison of Staff's and NEC's Estimates for Gas Turbines

No of Units	Rating (MW)	Current NOx Level (ppmv)	Incremental Emission Reduction per Unit from 2005 BARCT (tpd)	Staff's Estimate PWV per Unit ($M)	NEC's Estimate PWV per Unit ($M)
1	59	5.7	0.21	15.7 (new SCR)	5.1 (add catalysts)
3	46	3-4	0.31	12.6 (new SCR)	4.0 (add catalysts)
2	30	6	0.20	8.9 (new SCR)	2.6 (add catalysts)
1	23	5.7	0.14	7.2 (new SCR)	2.0 (add catalysts)
4	83	2.5-3.5	0.60	4.8 (add catalysts)	7.1 (add catalysts)
Total for all units			**4.14**	**97.68**	**52.7**

Staff's Recommendation

Staff recommends to set a new BARCT level of 2 ppmv NOx for refinery gas turbines since NOx control technologies such as DLE/DLN, CLN, SCR with CO catalysts, SCR with ASC are commercially available and can be used together to achieve 2 ppmv NOx in a cost-effective manner. A level of 2 ppmv NOx is achieved-in-practice for a turbine/duct burner 1,7 MW cogeneration unit using SCR and ammonia slip catalysts. An 83 MW cogeneration with SCR and CO catalysts was given a permit to construct since 2012 with a permit condition of 2 ppmv NOx.

In summary:

- Incremental Emission Reductions beyond 2005 BARCT level: 4.14 tons per day
- Total Estimated Incremental Costs Range: $52.7 (NEC) - 97.68 M (Staff)
- Average Incremental Cost Effectiveness: 1,452 – 2,692 $/ton (DCF) and 2K – 4.5K $/ton (LCF)

References for Gas Turbines

1. Refinery Survey Information. SCAQMD 2013.

2. Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines. EPA-453/R-93-007. January 1993.

3. Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines. Contract No. DE-FC02-97CHIO877. ONSITE SYCOM Energy Corporation. Prepared for U.S. Department of Energy. November 5, 1999.

4. SCR Costs Information from Manufacturer A. E-mails to Minh Pham on December 16, 2013 and March 12, 2014.

5. SCR Costs Information from Manufacturer B. E-mails to Minh Pham on November 25, 2013.

6. SCR Costs Information from Manufacturer C. E-mail to Refiner 10 on January 28, 2014.

7. Application and Engineering Evaluation for Permit to Construct of 85 MW Cogeneration. Email from R. Beshai to Minh Pham on November 7, 2013.

8. Costs Information and 2011 Fuel Gas Usage from Refinery 1. Email to Minh Pham on November 8 - 21, 2013.

9. Costs Information from Refinery 10. Email to Minh Pham from October 17, 2013 to January 31, 2014

10. Technology Characterization: Gas Turbines. Energy and Environmental Analysis. Prepared for Environmental Protection Agency Climate Protection Partnership Division, Washington, DC. December 2008.

11. Reducing NOx and NH3 Emissions with Advanced SCR Technology. Rita Aiello, Kevin Doura, Mike Baran, Wilson Chu, Paul Anderson, Johnson Matthey. Paper #33233. A&WMA's 107th Annual Conference & Exhibition, June 24-27, 2014, Long Beach California.

12. Catalytic Multi-Pollutant Abatement of Gas Turbine Exhaust. N. Jakobsson and H. Jensen-Holm. Environmental R&D and Environmental Catalyst. Haldor Topsoe. Downloaded from Haldor-Topsoe website in 2014. www.topsoe.com.

13. Selective Catalytic Reduction of NOx Emission from Gas Turbines with minimal Impact on Plant Performance. H. Jensen-Holm and P. Lindenhoff. SCR DeNOx Catalyst & Technology

Department. Haldor-Topsoe. Downloaded from Haldor-Topsoe Website in 2014. www.topsoe.com. 2 PPMV NOx

14. Dry Low NOx (DLN) Combustion Performance. www.ge-energy.com 3 PPMV

15. Latest Developments in Aero derivative Power Generating Systems. B. Naidu and P. Tinne. GE Aero-derivatives. Presentation at the SCAQMD. 2013

16. E-mail from B. Naidu to M. Pham on December 11, 2013.

17. Reduction of NOx and CO to Below 2 ppmv in a Diffusion Flame. V. Sahai and D.Y. Cheng. Proceedings of ASME Turbo Expo 2003. June 16-19, 2003.

18. Characteristics and Benefits of Simplified Combined Cycle. Electric Power Research Institute. EP-P32237/C15022. September 29, 2009.

19. Assessment of the Cheng Simplified Combined Cycle. Technical Update, December 2010.

20. CLN with SCR as an Emission Control System in CHP Plants Should Meet 2 ppmv NOx. Dr. Dah Yu Cheng, Ian Church, Ching-An Cheng. Paper #33051. A&WMA's 107th Annual Conference & Exhibition, June 24-27, 2014, Long Beach California.

21. Costs information provided by Cheng Combustion. E-mail from D. Cheng to Minh Pham on November 2013 – January 2014

22. CLN presentation to the SCAQMD staff, January 14, 2014.

23. Costs information on CLN. E-mail from Dr. Cheng to Minh Pham on January 10 and February 5, 2014.

24. Combating NOx from Refinery Sources Using SCR. Haldor Topsoe. Presentation at the 2nd Annual World Refining Technology Summit & Exhibition, 2010, Abu Dhabi. www.topsoe.com, posted online and downloaded in January 2014.

25. SCR and Zero-Slip™ Technology. T.W. Hastings of Cormetech, Inc. and A. Hattori of Mitsubishi Power Systems, Inc. Presentation of June 17, 2003 Turbo Expo – Atlanta, GA. 95% SCR efficiency. Ten units less than 2 ppmv NOx and 2 ppmv ammonia slip.

26. Dual Function Catalyst Promises High NOx Removal with Zero Ammonia Slip for Gas Turbine Applications. J.A. Rosin and H.S. Rosenberg. Power Engineering, September 2001, Vol. 105, Issue 9, page 76.

27. BASF NOxCat VNX & ZNX for Power Generation and Ammonia Destruction Catalysts. www.catalysts.basf.com.

28. Information on gas turbines from Refinery 5 to Minh Pham, December 3, December 17 and December 20, 2014.

29. SCAQMD engineering evaluation on Refinery 5 new cogeneration project. E-mail from Bob Sanford to Minh Pham, December 6, 2015.

30. E-mails from Refinery 5 to Minh Pham, December 3, 17, 20, 2013; January 16, 2014, and February 18 and 28, 2014.

31. Information from engineering evaluation on Refinery 7 Cogeneration unit. E-mail from Cynthia Carter to Minh Pham, February 27 and 28, 2014.

32. BASF NOx CAT VNX Catalyst and Zeolite. BASF Publication

33. BARCT Analysis for SCAQMD NOx RECLAIM, Non-Confidential Report, Norton Engineering Consultants, November 26, 2014

Appendix D - Coke Calciner

Process Description

Tesoro operates the sole coke calciner in the SCAQMD. Coke calcining is a process to improve the quality and value of "green coke" produced at a delayed coker in a refinery. The green feed, produced by the nearby Carson Refinery, is screened and transported to the coke calcining facility by truck, where it is stored under cover in a coke storage barn. The screened and dried green coke is introduced into the high end of the rotary kiln, 3 ft diameter x 270 ft long, is tumbled by rotation, and moves down the kiln countercurrent to a hot stream of combustion air produced by the combustion of natural gas or oil. The kiln temperatures are in a range of 2000 – 2500 degrees Fahrenheit. The green coke is retained in the kiln for approximately one hour to drive off the moisture, impurities, and hydrocarbon. After discharging from the kiln, the calcined coke drops into a cooling chamber, where it is quenched with water, treated with dedusting agents for dust control, and carried by conveyors to storage tanks. Later, the calcined coke is transported by trucks to the Port of Long Beach for export, or is loaded into railcars for shipments to domestic customers. A simplified process diagram of the calcining process is shown in Figure D.1.

The coke calciner produces approximately 400,000 tons per year of calcined products. This plant is a global supplier of calcined coke to the aluminum industry, and they provide fuel grade coke to the fuel, cement, steel, calciner, and specialty chemicals businesses. [1]

Emission Inventory

The 2011 NOx emissions from the coke calciner and current NOx outlet concentration are listed in Table D.1. The total 2011 emissions are 0.55 tons per day. The NOx outlet concentration at 65 ppmv is higher than the 2005 BARCT level of 30 ppmv (0.036 lb/mmBtu).

Table D. 1 - 2011 Emissions for Coke Calciner

Fac ID	Device ID	Device	2011 Emissions (lbs)	Current NOx at 3% O_2 (ppmv)
2	C67	Afterburner	390,625	65
2	D20	Rotary Kiln	11,400	65
Total (tpd)			**0.55**	

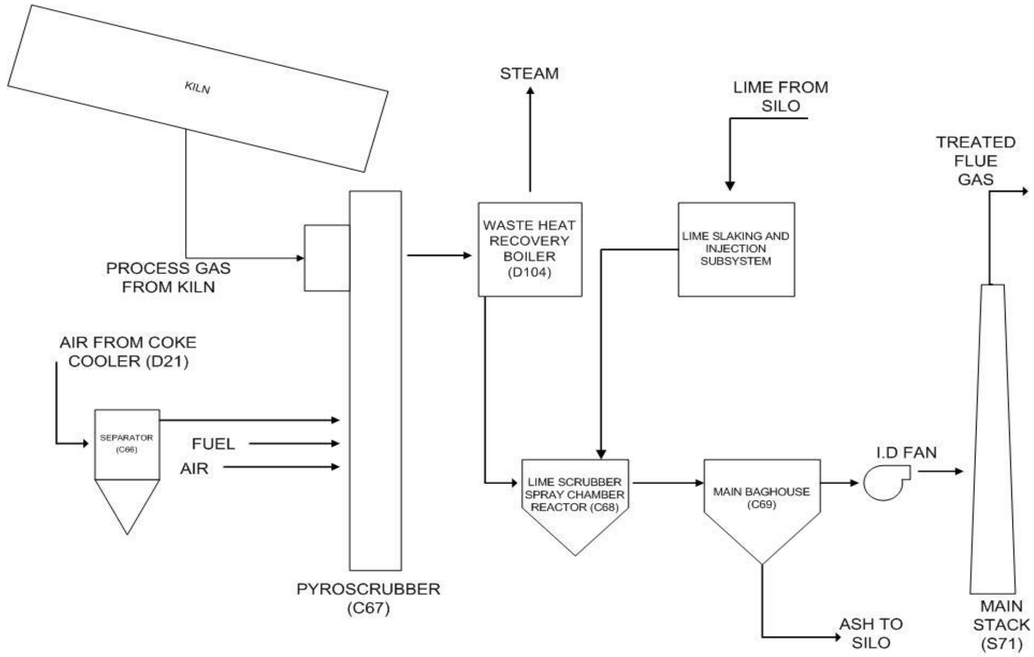


FIGURE 1: SIMPLIFIED PROCESS FLOW DIAGRAM

Figure D. 1 - Coke Calciner Process (Reference 1)

Control Technology

The commercially available control technologies for NOx emissions for the coke calciner are LoTOx and UltraCat, two commercially available multi-pollutant control technologies for low temperature removal of NOx.

LoTOx™ Application

LoTOx™ stands for "Low Temperature Oxidation" process where ozone is used to oxidize insoluble NOx compounds to soluble NOx compounds. LoTOx is a low temperature operating system, meaning that it does not require heat input to maintain operational efficiency and enables maximum heat recovery of high temperature combustion gases. In addition, LoTOx can be used with a wet (or semi-wet) scrubber, and together the system becomes a multi-component air pollution control system that can reduce NOx, SOx and PM concurrently. There are more than 50applications engineered by Linde LLC. since 1997, and more than two dozen applications with EDV™ scrubbers engineered by BELCO Dupont since 2007. [2-3] Applications in gas-fired and high sulfur coal-fired units met 2-5 ppmv. Current installations in refineries met 8-10 ppmv. The technology can be applied to coke calciner, and the manufacturer confirmed that LoTOx can be designed to achieve 2 ppmv NOx from current inlet concentrations of the coke calciner.

The 2010 SOx RECLAIM amendments set a BARCT level of 10 ppmv SOx for the coke calciner. It was determined that wet scrubbers engineered by BELCO, Tri-Mer and MECS were all feasible and cost effective. LoTOx application can be integrated in any of these scrubbers to reduce NOx, SOx, PM and other toxic pollutants. The footprint needed for scrubbers and associated equipment was estimated to be about 30 ft x 40 ft. The facility has not yet installed any scrubber since the adoption of the SOx RECLAIM amendments in 2010.

UltraCat™ Application

UltraCat is also a multi-component air pollution control technology developed by Tri-Mer. UltraCat catalyst filters are composed of fibrous ceramic materials embedded with proprietary catalysts that can remove NOx, SO_2, PM, HCl, Dioxins, and HAPs. The optimal operating temperatures are approximately 350 to 750 degrees F. Aqueous ammonia injected upstream of the catalytic filters is used to remove NOx. NOx removal efficiency is about 95%. Dry sorbent such as hydrated lime, sodium bicarbonate or trona injected upstream of the catalytic filters is used to remove SO_2, HCl, and other acid gases with a removal efficiency of 90% - 98%. Particulate control to a level of 0.001 grains/dcsf and mercury control are also possible. UltraCat filters are arranged in a baghouse configuration with low pressure drop, about 5" water column, and it has a reverse pulse-jet cleaning action (the filters are back flushed with air and inert gas to dislodge the particulate deposited on the outside of the filter tubes). Catalytic filter tubes are replaced every 5 to 10 years. The UltraCat catalytic filtering system is depicted in Figure D.2.

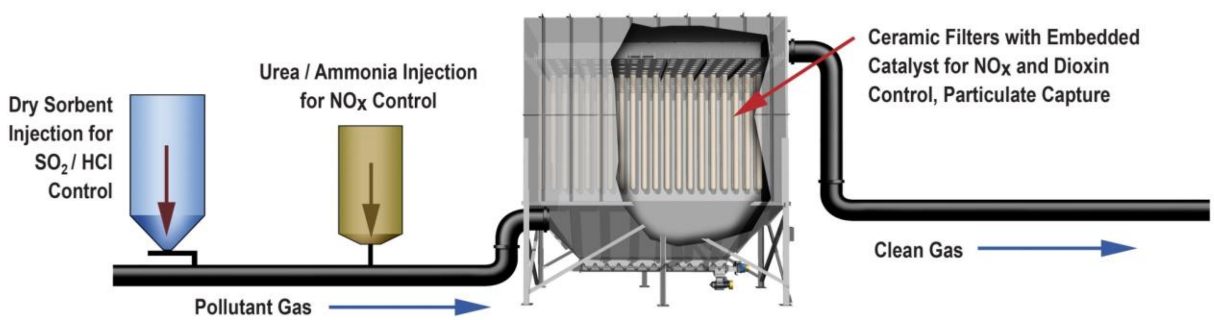


Figure D. 2 - Ultra-Cat Filters (Reference 5)[D2]

Costs and Cost Effectiveness

LoTOx™ Application

Table D.2 contains costs information provided by LoTOx manufacturer.[4] Staff estimated the PWV using the equations below for the Discounted Cash Flow (DCF) method assuming 4% interest rate and 25-years life for the control device. Staff applied a contingency factor of 1.5 to account for any additional costs that might occur. Incremental cost effectiveness was estimated as follows for the DCF method:

PWV = 1.5 x (TIC + (15.62 x AC)) (Equation 1)
CE = PWV / (ER x 365 days x 25 years) (Equation 2)

Where:
TIC = Total Installed Costs, $
AC = Annual Operating Costs, $
ER = Incremental Emission Reductions

In December 2014, the PWV and CE for LoTOx application were estimated to be $22 million and $10,347 per ton NOx reduced per DCF method as shown in Table D.3. The CE would be $17,073 per ton NOx reduced per Levelized Cash Flow (LCF) method.

UltraCat™ Application

Table D.2 contains costs information provided by UltraCat manufacturer.[6] In December 2014, staff estimated the TIC based on the OAQPS EPA Guidelines, i.e. TIC = 1.86 * Equipment Costs. Staff also applied a contingency factor of 1.5 to account for any additional costs that might occur. The PWV assuming 4% interest rate and 25-years life for the control device and the CE were estimated using Equations 1 and 2 shown above. The incremental emission reductions for Ultra-Cat system were estimated to be 0.23 tpd NOx and 0.28 tpd SOx

In December 2014, the PWV and incremental cost effectiveness for UltraCat application were estimated to be $61 million and $13,071 per ton NOx and SOx reduced estimated using DCF method as shown in Table D.3. The incremental cost effectiveness would be $13 K per ton NOx and SOx reduced estimated with the DCF method.

Table D. 2 – Costs of LoTOx and UltraCat for Coke Calciner (December 2014)

2011 NOx emissions	0.55 tons per day NOx
Current NOx concentration	64.95 ppmv NOx
2005 NOx BARCT level	30 ppmv NOx
2010 SOx BARCT level	10 ppmv SOx
2015 BARCT proposed level	2 ppmv NOx
2011 NOx emissions at 30 ppmv BARCT	0.25 tpd
2011 NOx emissions at 2 ppmv BARCT	0.02 tpd
Incremental NOx emission reductions	0.23 tpd
Flue Gas Temp	450 degrees F
Flue Gas Flow	6,806,770 dscfh (113,446 scfm)
Stack Oxygen	5%
Stack Moisture	29.8%
Coke Burned	81,471 tons per year
LoTOx Application for 2 ppmv NOx (97% control)	
Total Installed Costs	$6,250,000
Operating Costs	$544,300 per year
LoTOx Application for 5 ppmv NOx (92% control)	
Total Installed Costs	$6,200,000
Operating Costs	$516,800 per year
Ultra Cat Application for 2 ppmv NOx (97% control)	
Capital Costs of Emission Control	$7,531,774
Operating Costs – Utility, Catalysts, Labor, Maintenance	$1,721,490 per year
Filters replacement frequency	5 years at $215,600 per year

Table D. 3 - Cost and Cost Effectiveness Estimates for Coke Calciner (December 2014)

	Emission Reductions	PWV ($M)	Incremental CE ($/ton)
LoTOx	0.23 tpd NOx	22.13	10,374
UltraCat	0.23 tpd NOx + 0.28 tpd SOx	61.35	13,071

Consultant's Analysis for LoTOx and Staff's Revised Estimates for LoTOx and UltraCat

NEC suggested that a BARCT level of 2 ppmv was not feasible, and recommended 5 ppmv – 10 ppmv BARCT level for the coke calciner. NEC also suggested that a factor of 1.86 to estimate TIC and an adjustment of 1.5 were not conservative enough since space was extremely challenging at the coke calciner facility. A factor of 4.5 – 4.6 was more reasonable. Staff concurred with NEC recommendation and re-estimated the PWVs for the Ultra-Cat application as shown in Table D.4.

Table D. 4 – Revised Cost and Cost Effectiveness Estimates for Coke Calciner (March 2015)

	Staff's Estimates Using Factor of 4.5		NEC's Estimates
	BELCO	**Tri-Mer**	
BARCT Level	10 ppmv	92% control	10 ppmv
Incremental Reductions (tpd)	0.17	0.17+0.28=0.45	0.17
PWV ± 50% ($M)	54.29	91.17	39.50
Cost Effectiveness ($/ton)	$35K/ton	$22K/ton	$25K/ton

Staff's Recommendation

Staff recommends setting a BARCT level of 10 ppmv NOx for coke calciners because NOx control technologies such as LoTOx and UltraCat are commercially available to achieve this level in a cost-effective manner.

2014 BARCT NOx = (0.08 tpd)(2000 lb/ton)(365 days/yr)/(81,471 ton coke/yr) = 0.8 lb/ton coke

- Total incremental emission reductions beyond 2005 BARCT: 0.17 ton per day
- Total incremental costs: $39.5 million - $91 million
- Total incremental cost effectiveness: $22 - $35 K per ton

References for Coke Calciner

1. Staff Report of Proposed Amendments to SOx RECLAIM. Agenda 37 of the SCAQMD Governing Board Meeting. November 5, 2010.

2. LoTOx™ – Novel NOx Control Solution. Naresh J Suchak, Ph.D., Monica Caldwell, Peter Studer, Frank R Fitch, Ph.D., Linde Gases. Paper #33612. A&WMA's 107th Annual Conference & Exhibition, June 24-27, 2014, Long Beach California.

3. LoTOx NOx Reduction Technology Installation List. Dupont BELCO Clean Air Technologies, dated May 2013.

4. Costs for LoTOx Application to Meet 2 ppmv NOx for 3 FCCUs and Coke Calciner in the SCAQMD. Email of information provided by LoTOx manufacturer to Minh Pham. December 12, 2013 and January 20, 2014.

5. Tri-Mer UltraCat Catalytic Filters – Brochure downloaded from www.trimer.com in January 2014.

6. Costs for UltraCat Application to Meet 2 ppmv NOx for Coke Calciner in the SCAQMD. Emails of information provided to Minh Pham. November 8, 2013 and May 21, 2014.

7. BARCT Analysis for SCAQMD NOx RECLAIM, Non-Confidential Report, Norton Engineering Consultants, November 26, 2014

Appendix E - Sulfur Recovery Units/Tail Gas Incinerators

Process Description

A sulfur recovery unit and tail gas treatment unit (SRU/TGTU) at the refineries include a Claus unit followed by an amine absorption unit to recover the sulfur from various gaseous. The SRU (Claus unit) consists of a reactor and series of converters and condensers. Approximately 95% of sulfur from the gaseous streams is recovered after passing through the SRU. The tail gas is then sent to an amine absorption unit, or diethanol amine (DEA), SCOT, Wellman-Lord, and FLEXSORB to absorb and recover the remaining sulfur. Approximately 99% or the remaining sulfur is absorbed and recovered after the amine units. The tail gas is then vented to a thermal (or catalytic) oxidizer (incinerator) where the residual H_2S in the tail gas is oxidized to SO_2 before emitting to the atmosphere. The refinery SRU/TGTUs including their incinerators are classified as major sources of NOx and SOx.
Since the interception of the RECLAIM in 1993 until 2010, no Best Available Retrofit Control Technology (BARCT) standards have been established for the SRU/TGTUs and incinerators. The 2010rule amendment included a new BARCT level for SOx at 5 ppmv, 0% O2. At that time, it was determined that Refineries 1, 5, and 6 could retrofit their SRU/TGTUs cost-effectively with wet gas scrubbers (WGS) to further reduce SOx emissions. The construction time was estimated to be about 3 years. [1] As of today, Refineries 1, 5 and 6 did not retrofit any of their existing SRU/TGTUs, instead they selected to purchase RECLAIM Trading Credits or reduce SOx elsewhere in the refinery to comply with their facility emission caps. In 2011, Refinery 5 installed a new SRU/TGTU at their refinery and evaluation of the performance is ongoing.

Emission Inventory

The 2011 NOx emissions from the SRU/TGTUs and incinerators in the SCAQMD and their current NOx outlet concentration are shown in Table E.1. The total 2011 emissions are 0.43 tons per day. The NOx concentrations at the stack vary widely from 6 ppmv to 70 ppmv. It should be noted that their SOx emissions also vary widely from 20 ppmv to 150 ppmv.

Table E. 1 - 2011 Emissions for SRU/TG Incinerators

Unit	Fac ID	Device ID	Device	2011 Emissions (lbs)	Existing NOx @ 3% O2
1	9	1260	INCINERATOR	7,696	66.81
2	6	952	INCINERATOR	41,066	6.57
3	5	911	INCINERATOR	28,379	29.00
4	5	913	HEATER	12,087	29.00
5	5	927	INCINERATOR	14,276	27.00
6	5	929	HEATER	6,080	29.00
7	5	955	INCINERATOR	40,313	29.83
8	5	957	HEATER	13,035	29.83
9	1	910	INCINERATOR	42,273	28.07
10	1	2413	INCINERATOR	22,337	18.33
11	10	175	INCINERATOR	5,674	45.89
12	3	54	INCINERATOR	13,115	55.00
13	3	56	INCINERATOR	4,931	55.00
14	7	436	INCINERATOR	8,030	18.68
15	7	456	INCINERATOR	7,025	31.85
16	8	294	thermal INCINERATOR	49,563	32.00
17	8	292	catalytic INCINERATOR	1,010	not reported
			Total (tpd)	**0.43**	

Control Technology

Commercially available control technologies for NOx emissions are Selective Catalytic Reduction (SCR) and LoTOx. KnowNOx has been installed at two locations in the U.S. however has not yet been tested in any refinery applications. While SCR is considered a high temperature NOx reduction technology, LoTOx and KnowNOx are known for low temperature multi-pollutant control systems since they can be integrally connected with a WGS to reduce NOx, SOx, PM, VOCs, HAPs, and other toxic compounds.

Selective Catalytic Reduction

For the past two decades, SCR technology has been used successfully to control NOx emissions. The technology is considered mature and commercially available. The advanced SCRs can be designed to reduce 95%-98% NOx emissions from the SRU/TGTUs and incinerators and achieve 2 ppmv NOx while maintaining a low ammonia slip of less than 5 ppmv. [3-14]

LoTOx^{TM} Application

LoTOx^{TM} stands for "Low Temperature Oxidation" process where ozone is used to oxidize insoluble NOx compounds to soluble NOx compounds which can be subsequently removed by absorption in caustic solution, lime or limestone. Please refer to Appendix A for details. There are more than 50 LoTOx applications engineered by Linde LLC., and two dozen applications engineered by BELCO of Dupont for refinery FCCU applications.[15, 22] While BELCO's expertise is in the refinery FCCUs, its sister company MECS has engineered more than two dozen DynaWave scrubbers specifically designed for refinery SRU/TGTUs. Figure E.1 shows a schematic for a DynaWave scrubber. Figure E-2 contains a schematic for LoTOx process incorporated into the DynaWave scrubber.

Currently, LoTOx applications in the FCCU applications have achieved 8 ppmv - 10 ppmv NOx, and 2 ppmv – 5 ppmv NOx in gas-fired and high sulfur coal-fired units. [15, 22] LoTOx technology can be incorporated to the refinery SRU/TGTUs' incinerators and designed to achieve a level of 2 ppmv NOx outlet concentrations.[24]

Table E.3 has a list of the DynaWave installations in the U.S. [25] This is not an inclusive list. In addition to refinery SRU/TGTU applications, DynaWave scrubbers are used in numerous other industrial applications such as sulfuric acid plants, coke calciner, metallurgical plants, secondary aluminum or copper smelters, coal fired heaters and boilers, sulfur pits, platinum recovery plants, cement kilns, meat rendering plants, and medical waste incinerators. DynaWave scrubbers have been used in the industries since 1987.

A BARCT level for SOx was established at 5 ppmv, 0% O_2, annual average in 2010. In 2011, Refinery 5 installed a new SRU/TGTU with a DynaWave scrubber to meet a short-term BACT standard of 10 ppmv. The most recent source test data shows that the DynaWave scrubber meets <1 ppmv SOx, corrected to 0% O_2. Thus, concurrent reductions of NOx and SOx are feasible and cost-effective using a DynaWave and LoTOx combination application.

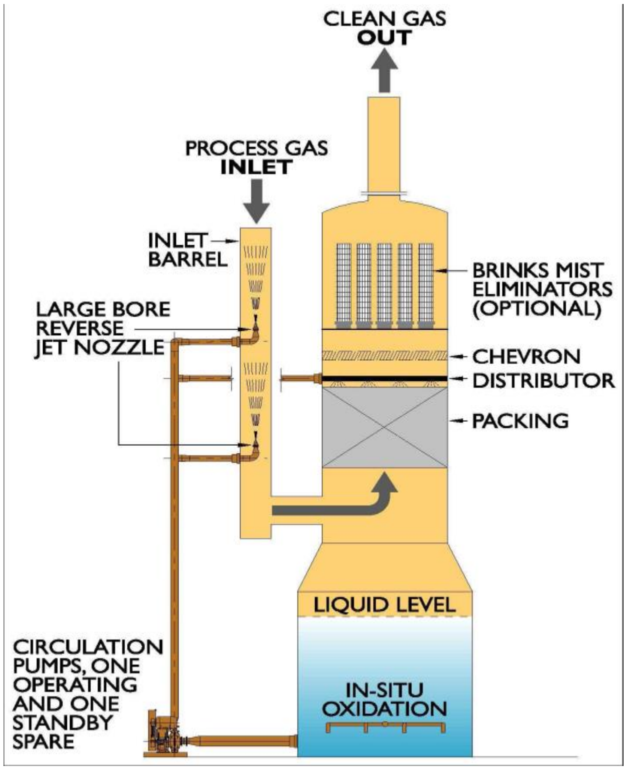


Figure E. 1 - DynaWave Scrubber (Reference 23)

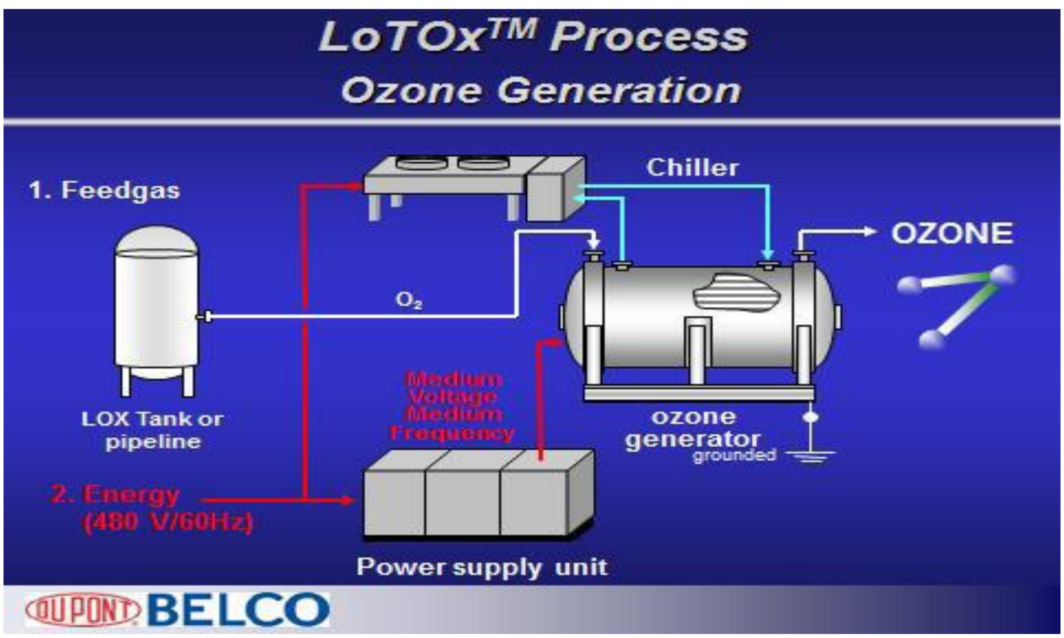


Figure E. 2 - Ozone Generation Process (Reference 23)

Table E. 2 - List of DynaWave Scrubber Installations for SR/TGTUs

Company/Location	StartUp Date	Exit Gas ACFM	Application
KiOR	2012	82,135	BioRefinery FCC Off Gas
Mississippi			Quench, SO_2 and Particulate
Calumet	2010	15,545	40 LTPD SRU Tail Gas Clean Up
Louisiana			SO_2 removal with NaOH
Chevron	2013	27,800	SRU SCOT Tail Gas Clean Up
California			SO_2 removal with NaOH
Sinclair	2009	59,603	FCC Off Gas
Oklahoma			Quench, SO_2 and Particulate
Wyoming Refining	2011	57,746	FCC Off Gas
Wyoming			Quench, SO_2 and Particulate
Pasadena Refining	2008	2,200	S Zorb Off Gas
Texas			SO_2 removal with NaOH
ConocoPhillips	2006	6,700	S Zorb Off Gas
Illinois			PM and SO2 removal with NaOH
Sinclair	2006	9,000	25 LTPD SRU Tail Gas Clean Up
Oklahoma			SO_2 removal with NaOH
Marathon Ashland	2008	10,100	33 LTPD SRU Tail Gas Clean Up
Texas			SO_2 removal with NaOH
Sinclair	2005	12,830	47.5 LTPD SRU Tail Gas Clean Up
Wyoming			SO_2 removal with NaOH
Sinclair	2005	5,700	18 LTPD SRU Tail Gas Clean Up
Wyoming			SO_2 removal with NaOH
ConocoPhillips	2005	2,000	S Zorb Off Gas
Louisiana			SO_2 removal with NaOH
Navajo	2003	100,000	FCC off gas NaOH scrubber for SO_2 and PM
New Mexico			
ConocoPhillips	2003	3,300	S Zorb Offgas
Washington			SO_2 removal using NaOH
Unocal Refining	1993	17,300	Spent sulfuric acid plant
California			
Hess Oil St. Croix	1993	9,400	Spent sulfuric acid plant
Virgin Islands			Gas cleaning for new plant
Sun Refining	1991	2,000	H2S and sour water incinerator
Pennsylvania			Particulate and SO3 removal
BP	1990	130,000	Coke calciner
Washington			PM/SO2 removal with soda ash

KnowNOx™ Application

In lieu of using ozone to convert NO and NO_2 to N_2O_5 and HNO_3, the KnowNOx technology uses chlorine dioxide ClO_2. The conversion reactions (Reactions 12 and 13) are in the gas phase, which can occur much faster than the liquid phase reactions with ozone (Reactions 5 and 6). It takes less than 0.5 seconds to achieve 99.8% or more conversion. The reactions require a smaller vessel in relative to the LoTOx reaction chamber. In addition, the KnowNOx process can simultaneously reduce NOx, SO_2, PM and other contaminants.[26-28]

$5\,NO + 2\,ClO_2 + H_2O \rightarrow 5\,NO_2 + 2\,HCl$ (Reaction 12 - Gas Phase)
$5\,NO_2 + ClO_2 + 3\,H_2O \rightarrow 5\,HNO_3 + 2\,HCl$ (Reaction 13 – Gas Phase)
$5\,SO_2 + 2\,ClO_2 + 6\,H_2O \rightarrow 5\,H_2SO_4 + 2\,HCl$ (Reaction 10)

The conceptual layout for the KnowNOx process is shown in Figure E.3. It includes a three-stages scrubbing system: SO_2 is scrubbed at the 1st stage with a DynaWave scrubber, ClO_2 injected to the 2nd stage converts NO and NO_2 to HNO_3 and other soluble salts, and H_2S generated in the 2nd stage is converted to soluble salts in the 3rd stage. The KnowNOx technology has been installed at two locations in the U.S., however, it has not yet been tested in any refinery applications, and may not yet have been proven at full scale operations.

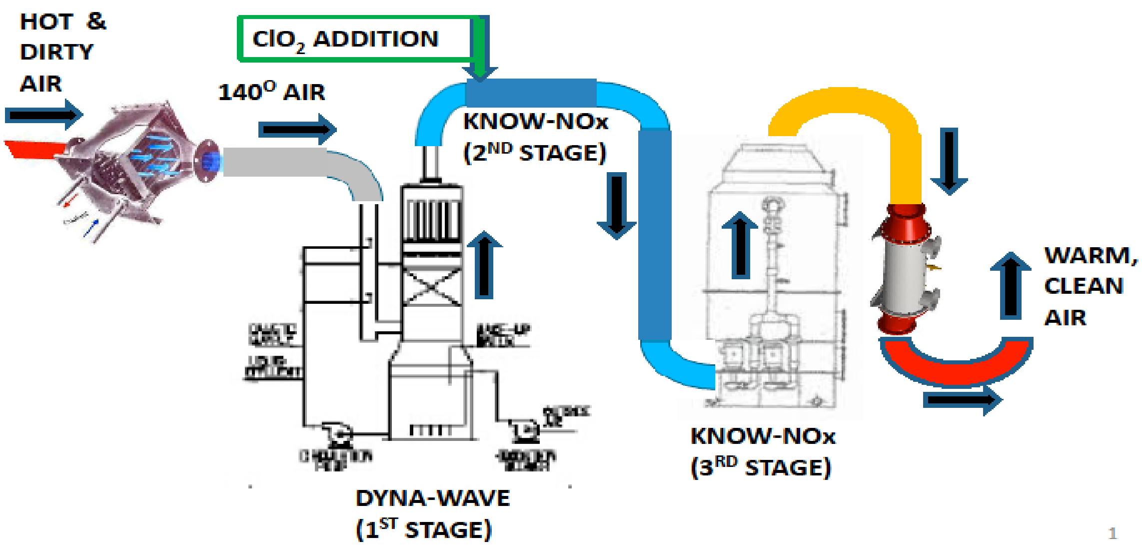


Figure E. 3 – KnowNOx Process (Reference 28)

Costs and Cost Effectiveness

Selected process conditions and the outlet NOx concentrations of the SRU/TGTUs at the refineries in the SCAQMD are listed in Table E.3. To obtain control equipment cost information, staff provided the manufacturers with the information for the three scenarios listed in Table E.4. These scenarios reflect the units with highest emissions and flue gas flow rates from the 17 SRU/TGTUs/incinerators in the SCAQMD.

Staff estimated the PWV for the control system using Equation 1 below assuming 4% interest rate and a 25-years life for the control device:

PWV = (Contingency Factor) x (TIC + (15.62 x AC) + (2.52 x CR)) (Equation 1)

Where:

PWV = Present Worth Value, $
TIC = Total Installed Costs, $
AC = Annual Operating Costs, $
CR = Catalyst Replacement every 5 years
Contingency factor = 1.5

Staff used the factors in the EPA OAQPS Guidelines to estimate the TIC and a contingency factor of 1.5 was added to the TIC and AC to account for operational uncertainties. CE was estimated as shown in Equation 2 using the DCF method. For comparison, the incremental cost effectiveness would be about 1.65 higher if it was calculated using the LCF method:

CE = PWV / (ER x 365 days x 25 years) (Equation 2)

Where:

CE = Incremental Cost Effectiveness, $/ton
PWV = Present Worth Value, $
ER = Incremental Emission Reductions, tpd

Costs for SCRs

Manufacture A's estimates are summarized below: [13]

- It is feasible to achieve 2 ppmv NOx and 5 ppmv ammonia slip,
- All three scenarios would result in about the same costs,
- Costs for SCR catalysts would be about $600,000 and installation costs about $600,000,
- Add costs for heat exchangers in Scenario 1 and 2, and
- Inlet NOx could be higher but would not affect the overall cost estimates.

Table E. 3 - Process Information and NOx Emissions for SRU/TG Incinerators in SCAQMD

Unit	Fac ID	Device ID	Device	Max Rating (mmbtu/hr)	Flue Gas Flow rate (dscfm)	Flue Gas Temp (degree F)	Existing NOx (ppmv)
1	9	1260	INCINERATOR	36			66.81
2	6	952	INCINERATOR	100	34,640	1,080	6.57
3	5	911	INCINERATOR	30	12,500	515	29.00
4	5	913	HEATER	25	12,500	515	29.00
5	5	927	INCINERATOR	30	12,500	570	27.00
6	5	929	HEATER	25	12,500	570	29.00
7	5	955	INCINERATOR	58	14,500	520	29.83
8	5	957	HEATER	41	14,500	520	29.83
9	1	910	INCINERATOR	45	32,167	1,260	28.07
10	1	2413	INCINERATOR	40	27,167	1,292	18.33
11	10	175	INCINERATOR	10			45.89
12	3	54	INCINERATOR	52			55.00
13	3	56	INCINERATOR	45			55.00
14	7	436	INCINERATOR	20			18.68
15	7	456	INCINERATOR	20			31.85
16	8	294	thermal INCINERATOR	28	23,284		32.00
17	8	292	catalytic INCINERATOR	15			

Table E. 4 – NOx and SOx Performance of SRU/TG Applications in SCAQMD

	Scenario 1 Refinery 6	Scenario 2 Refinery 1	Scenario 3 Refinery 5
Incinerator Rating	100 mmBtu/hr	45 mmBtu/hr	100 mmBtu/hr (note)
Average flue gas flow rate	36,000 dscfm	32,000 dscfm	14,500 dscfm
Temperature	1,100 degrees F	1,200 degrees F	520 degrees F
O2 %	2.5%	6% - 8%	4%
Current NOx concentration	21 ppmv	28 ppmv	30 ppmv
Current SOx concentration	40 ppmv	75 ppmv	20 ppmv

Note: Incinerator 58 mmBtu/hr and heater 41 mmBtu/hr are vented to a common stack

Manufacturer B's estimates are summarized below: [14]

- It is feasible to achieve 2 ppmv NOx and 5 ppmv ammonia slip,
- SCR costs for Scenario 1 and 2 were estimated to be about $461,000 for SCR at 80% NOx control efficiency. SCR costs for Scenario 3 would be about 10% less than Scenario 1 and 2.
- Costs for a system at 90% control efficiency would be about 5% higher than the costs for a system at 80% control efficiency.
- Costs for a system with 95% control efficiency would be about 10% higher than the costs for a system at 80% control efficiency.
- Estimated costs would not vary with inlet NOx concentration
- SCR footprint and dimension:
    - Catalysts with 1 layer and 1 module for a system with 85% control efficiency. Add 3 in of catalysts for a 95% control efficiency system
    - Add 2 ft in each direction for structural steel, and 6" for insulation
    - SCR overall dimension: 15 ft x 15ft x 15 ft
- Heat exchanger would be required for Scenarios 1 and 2 to lower the temperatures to the optimum temperatures of about 750 degrees F
    - Heat exchanger would cost about $100,000
    - Dimension for a horizontal flow heat exchanger: 6 ft Dia x 6ft - 10 ft L.
- Ammonia usage (19% aqueous ammonia):
    - 11.1 lb/hr for 80% removal, 12.1 lb/hr for 90% control, 12.6 lb/hr for 95% control
    - About $82,000 per year NH_3 costs and $40,000 miscellaneous for a 95% control
    - Dimension of 2000-gallons NH_3 storage tank: 4 ft D x 24 ft L, or 6 ft D x 10 ft L.
    - Ammonia storage tank costs $15,000 (30 days supply)
- Catalyst replacement would be every 5 years. Replacement frequency would depend on actual flue gas constituents and could be guaranteed for a turnaround cycle.

Costs for LoTOx™ Applications

MECS's cost estimates for LoTOx system to reduce NOx emissions are shown in Table E.5. MECS also provided costs for DynaWave and LoTOx in one system to reduce both NOx and SOx emissions as shown in Table E.5. [24]

Table E. 5 – Cost Information Provided by MECS

	Scenario 1		Scenario 2		Scenario 3	
	LoTOx	Dynawave LoTOx	LoTOx	Dynawave LoTOx	LoTOx	Dynawave LoTOx
Inlet Temp, degrees F	1,100	1,100	1,200	1,200	520	520
Inlet Flow, scfm	38,710	38,710	34,409	34,409	15,761	15,761
Outlet Temp, degrees F	158	158	161	161	139	139
Outlet Flow, scfm	52,782	52,782	48,329	48,329	18,021	18,021
Total Installed Costs, $	5,666,000	8,432,000	5,605.000	8,311,000	4,903,237	6,907,000
Operating Costs, $/yr	89,356	260,600	98,713	276,110	47,000	73,650

Costs for KnowNOx™ Applications

Costs provided by KnowNOx for its system to reduce only NOx emissions are shown in Table E.6. KnowNOx also provided costs for DynaWave scrubber in combination with its technology to reduce both NOx and SOx emissions.[29]

Table E. 6 – Cost Information Provided by KnowNOx

	Scenario 1		Scenario 2		Scenario 3	
	KnowNOx	Dynawave KnowNOx	KnowNOx	Dynawave KnowNOx	KnowNOx	Dynawave KnowNOx
Inlet Flow, scfm	36,000	36,000	32,000	32,000	14,500	14,500
Total Installed Costs, $	1,420,225	4,220,226	1,398,286	4,198,286	1,401,825	3,402,226
Operating Costs, $/yr	108,284	289,936	112,957	295,948	198,729	227,337

In 2014, staff estimated that SCRs, LoTOx and KnowNOx would be cost-effective for 10 SRU/TGTUs (out of 17 units) at Refineries 1, 5, 6 and 8. The PWVs for SCRs, LoTOx and KnowNOx were estimated to be $48.7 M, $68 M and $39 M respectively. The cost effectiveness for the 7 SCRs was estimated to be $15 K per ton NOx reduced (DCF) and $25 K per ton NOx reduced (LCF) as shown in Table E.7.

Consultant's Analysis for SCRs and Staff's Revised Estimates for SCRs and LoTOx

NEC confirmed that the 2 ppmv proposed BARCT level is feasible for the refinery SRU/TG incinerators. However, the consultants indicated that the factor of 1.86 from the EPA OAQPS Guidelines was low and suggested staff used a factor of 4.5. NEC also recommended using SCRs with 3 layers of catalysts and added the costs of waste heat boilers, new ammonia tanks and associated equipment. A comparison of NEC's and staff's estimates is shown in Table E.7.

Table E. 7 - Comparison of SCR Costs Estimated by Staff and NEC for SRU/TGTUs (December 2014)

	Staff's Estimates for SCRs	NEC's Estimates for SCRs
PWVs for SCRs	$ 48.7 M	$ 96.4 M
Cost Effective Units	10	9
Emission Reductions	0.35 tpd	0.32 tpd
Cost Effectiveness (DCF)	15,233 $/ton	33,014 $/ton

Staff revised the cost estimates using the factor of 4.5 recommended by NEC. The revised estimates are shown in Table E.8. Per these revised estimates, there would be 9 cost effective SRU/TG units with a total incremental emission reductions of 0.32 tpd at PWVs of $82.5 M for SCRs or $105.8 M for LoTOx applications.

Table E. 8 - Revised Cost and Cost Effectiveness Estimates for SCRs and LoTOx for SRU/TGTUs (March 2015)

Fac ID	Dev	SCR			LoTOx		
		AQMD ($M)	**Reductions (tpd)**	**AQMD CE ($/ton)**	**AQMD ($M)**	**Reductions (tpd)**	**AQMD CE ($/ton)**
6	D952	16.2	0.05	33,298	22.7	0.05	46,458
5	911/913	11.3	0.05	23,491	18.9	0.05	39,321
5	927/929	11.3	0.03	46,697	18.9	0.03	78,167*
5	955/957	11.3	0.07	17,818	18.9	0.07	29,826
1	910	17.3	0.06	34,379	22.7	0.06	45,127
1	*2413*	*16.9*	*0.03*	*63,593***	*22.7*	*0.03*	*85,404***
8	294	15.2	0.06	25,805	22.7	0.06	38,490
Total for cost-effective units		**82.5**	**0.32**	**28,270**	**105.8**	**0.29**	**39,963**

*this unit was cost effective using SCR technology thus was included in the revised analysis. ** this unit was not cost effective using either SCR or LoTOx thus was not included in the revised cost analysis.

Staff's Recommendation

Staff recommends to set a new BARCT level of 2 ppmv NOx for SRU/TG incinerators (95% control efficiency) because NOx control technologies such as SCR and LoTOx (or KnowNOx) with DynaWave scrubbers are commercially available and can de designed to achieve 2 ppmv NOx in a cost-effective manner.

In summary:

- Incremental Emission Reductions beyond 2005 BARCT level: 0.32 tons per day
- Number of cost effective units: 9
- Total Incremental Costs: \$83 M ± 50% with SCRs - \$106 M ±50% with LoTOx
- Average Incremental Cost Effectiveness (DCF method):
    - \$28K per ton NOx reduced with SCRs
    - \$40K per ton NOx reduced with LoTOx applications
- Average Incremental Cost Effectiveness (LCF method):
    - \$46K per ton NOx reduced with SCRs
    - \$66K per ton NOx reduced with LoTOx applications.

References for SRU/TG Incinerators

1. Staff Report of Proposed Amendments to SOx RECLAIM. Agenda 37 of the SCAQMD Governing Board Meeting. November 5, 2010.

2. EPA Air Pollution Cost Manual, Section 4 – NOx Controls, EPA/452/B-02-001, Sixth Edition, January 2002.

3. Reducing NOx and NH3 Emissions with Advanced SCR Technology. Rita Aiello, Kevin Doura, Mike Baran, Wilson Chu, Paul Anderson, Johnson Matthey. Paper #33233. A&WMA's 107th Annual Conference & Exhibition, June 24-27, 2014, Long Beach California.

4. UltraCat Catalytic Filters Remove PM, SO_2, HCl, NOx, Dioxins and HAPs. NOx Control as Low as 350 degrees F – TriMer's brochure – www.tri-mer.com.

5. Combating NOx from Refinery Sources Using SCR. Haldor Topsoe. Presentation at the 2nd Annual World Refining Technology Summit & Exhibition, 2010, Abu Dhabi. www.topsoe.com, posted online and downloaded in January 2014.

6. Information posted online at the website for Mitsubishi and Cormetech, www.cormetech.com/non-reductionh.htm, and www.mhpowersystems.com/scr.html, downloaded on January 2014.

7. SCR and Zero-Slip TM Technology. T.W. Hastings of Cormetech, Inc. and A. Hattori of Mitsubishi Power Systems, Inc. Presentation of June 17, 2003 Turbo Expo – Atlanta, GA.

8. Dual Function Catalyst Promises High NOx Removal with Zero Ammonia Slip for Gas Turbine Applications. J.A. Rosin and H.S. Rosenberg. Power Engineering, September 2001, Vol. 105, Issue 9, page 76.

9. Optimization of Ammonia Source for SCR Applications. R. Salib and R. Keeth of Washington Group International. Paper Poster Session No. 46. (no date)

10. Comparison of Urea Based Ammonia to Liquid Ammonia Systems for NOx Reduction Applications. J. E. Fisher, WAHLCO, Inc.

11. Comparison of Urea, 19% Aqueous Ammonia, and Anhydrous Ammonia Operating Costs. of Canyon Energy Project. D. Kirk of Fuel Tech Inc. to C. McFarlin of California Energy Commission, September 3, 2008.

12. Influence Factors and Control Research on Ammonium Bisulfate Formation in the Process of Selective Catalytic Reduction. S. Ma et.al., North China Electric Power University. Journal of the Air & Waste Manuscript Paper UAWM-2013.

13. SCR Costs Information from Manufacturer A. E-mail to Minh Pham on May 5, 2014.

14. SCR Costs Information from Manufacture B. E-mails to Minh Pham on May 8 and May 14, 2014.

15. LoTOx^{TM} – Novel NOx Control Solution. Naresh J Suchak, Ph.D., Monica Caldwell, Peter Studer, Frank R Fitch, Ph.D., Linde Gases. Paper #33612. A&WMA's 107th Annual Conference & Exhibition, June 24-27, 2014, Long Beach California.

16. Meeting Tighter NOx Emission Rules – A Low Temperature Oxidation Technology Uses Ozone to Remove Very Low Levels of Nitrogen Oxide from Refinery Gases. S. Harrison, N. Suchak, F. Fitch, Linde Gases. www.digitalrefining.com/article/1000954. PTQ Q3 2014

17. Wet Scrubbing-based NOx Control Using LoTOx Technology – First Commercial FCC Start-Up Experience. Nicholas Confuorto of BELCO Technologies, Jeffrey Sexton of Marathon Petroleum Company LLC. www.digital refining.com/article/1000812. September 2007

18. Preparing Wet Scrubbing Systems for a Future with NOx Emission Requirements. S. Eagleson and N. Confuorto, BELCO Technologies Corporation, www.digitalrefining.com/article/100833. September 2013.

19. Low Temperature Oxidation System. California Air Resources Board Grant Number ICAT 99-1. www.arb.ca.gov/research/icat/projects/boc.htm#.

20. Pilot-Scale Studies on NOx Removal from Flue Gas via NO Oxidation and Absorption into NaOH Solution. M. Jakubiak, W. Kordylewski. Wroclaw University of Technology, Faculty of Mechanical and Power Engineering, Institute of Power Engineering and Fluid Mechanics, Poland.

21. Acid Gas Scrubber for Muti-Pollutant Reduction. Nicholas Confuorto, BELCO. Institute of Clean Air Companies (ICAC) - Emission Control and Measurement Workshop. March 24-25, 2010.

22. LoTOx NOx Reduction Technology Installation List. Dupont BELCO Clean Air Technologies. May 2013.

23. MECS Presentation to SCAQMD. S. Whitlock, S. Myer of MECS Dupont. June 4, 2014.

24. Costs for LoTOx Applications from MECS. Email from Stephen Whitlock to Minh Pham. May 28, 2014.

25. DynaWave Scrubber Installation List. Email from S. Whitlock of MECS to Minh Pham. September 15, 2014.

26. Pacific Rim Design & Development NOx Control Technology. Presentation to SCAQMD. D. Schwartzel of Dupont. 2013.

27. NOx Scrubbing Technology Breakthrough. Confidential Material. R. Richardson of KnowNOx. November 2013,

28. KnowNOx Presentation to SCAQMD. R. Richardson of KnowNOx. June 4, 2014.

29. Costs for KnowNOx Technology. E-mailsfrom R. Richardson to Minh Pham. June 2, 2014, and July 29, 2014.

30. BARCT Analysis for SCAQMD NOx RECLAIM, Non-Confidential Report, Norton Engineering Consultants, November 26, 2014.

Appendix F - Comparative Analyses for FCCUs

This appendix provides a comparison of the selective catalytic reduction (SCR) design configuration, total installed cost (TIC) calculation and present worth value (PWV) estimation methodologies used in the staff and NEC cost effectiveness calculation for the FCCUs. Table F.1 summarizes the basic comparison. Variations in the SCR size, cost assumptions, TIC and PWV estimation methodology are provide in a side by side comparison for evaluation.

Table F.1 - Comparison of Staff and NEC Control Equipment Designs, TIC and PWV Estimation Methods

	Staff's Design	**NEC's Design**
SCR Configuration	2-Catalyst layers 3-Beds: 1-reserve	3-Catalyst layers 3-Beds: all used
Cost Models	SCR costs directly provided by Refinery 1 (2 catalyst layers) and the manufacturers (2-catalyst layers) SCR cost for Refinery 5, 6 and 7 scaled to Refinery-1 based on flow rate. SCR cost for Refinery 4 and 9 provided directly by the manufacturers.E	SCR cost provided by vendor (2 catalyst layers 12.8 feet per second). SCR vendor based costs curve (scaled for 3-layers, 10 feet per second) With NEC modifications and refinery input including: • 1.35 bid conditioning factor, • 1.75 labor factor, and • 4.5 TIC factor
Additional Costs		Waste Heat Boiler Modifications, New CEMS, NH3 Storage
Refinery Cost Application		
Refinery-1	Refinery -1 data	N/A
Refinery-4 & 9	EPA Methodology with 1.5 contingency for PWV. NEC additional costs assumed in the contingency factor.	Cost Curve
Refinery-5	Scaled to Refinery-1	Cost Curve
Refinery-6	Scaled to Refinery-1	Cost Curve
Refinery-7	Scaled to Refinery-1	Cost Curve
All Refineries	SCR cost provided by manufacturer (2 catalyst layers) with NEC additional costs included.	

Summary of Staff's Approach

Staff presented two approaches to estimate the SCR PWV for the 6 FCCUs operating in the Basin. (Note: two FCCUs are not controlled using SCRs). The first approach estimated PWV using data directly obtained from Refinery1 to establish PWV, while 3 additional SCR PWV were scaled from the Refinery 1 estimate. Two additional SCR PWV profiles were estimated using manufacturer provided cost information and the EPA cost model with a 150 percent contingency.

The second approach used the NEC model for the manufacturer's SCR designed for 2-catalyst layers. The two methods provided a range of PWV and CE as reported in Appendix A.

Approach #1

- Refinery 1 submitted capital costs and annual operating costs for their FCCU SCR in 2013. The FCCU SCR was installed in 2003 with 2 layers of catalysts and 1 spare layer and achieved 2 ppmv NOx.

- Using the cost information submitted directly by Refinery 1 to estimate the PWV would result in \$41 M. Using the NEC equation (derived for a 3-catalyst layer SCR from data provided by a manufacturer) the PWV would result in \$52 M. The PWV estimated based on NEC's approach and equation would be about 26% higher than that estimated using the actual costs submitted by Refinery 1.

- Staff scaled the Refinery 1 SCR PWV cost using the of Refinery 1 SCR and the ratios of their appropriate inlet flue gas flow rates to the 0.7 power to project PWV for Refineries 5, 6, and 7.

- PWV for Refineries 4 and 9 was estimated using SCR manufacturer cost data and the U.S. EPA Guideline approach with a 150 percent contingency markup.

Approach #2

Staff used the NEC approach to develop a cost curve based on the SCR manufacturer's design of 2-catalyst layers.

The NEC cost assumptions included:

- 1.35 for a bid conditioning factor
- 1.75 adjustment for labor
- 4.5 factor to relate the equipment costs to a TIC
- Staff added the NEC estimated costs of a waste heat boiler, new CEMS, and costs of ammonia storage tank.

PWV estimated for 2-catalyst layers vs. 3-catalyst layers

A comparison of the PWV estimates calculated for Refinery 9 using the manufacturer 2-layer SCR model (with and without selected cost markups) and the NEC 3-layer SCR model and the EPA methodology is presented in Table F.2.

Table F. 2 - Comparison of Cost Estimates for FCCU's SCR

	NEC's Design	Manufacturer's Design (note)				EPA Methodology
Layers of catalysts	3	2	2	2	2	with 50%
1.35 Markup	Yes	Yes	No	Yes	No	Contingency
1.75 Markup	Yes	Yes	Yes	No	No	
Total Installed Costs , $M	**31.6**	**26.4**	**21.5**	**18.3**	**15.5**	**16.13**
PWV, $M	**39**	**32**	**27**	**24**	**21**	**19**

Note: The TIC include the costs of SCR provided by vendor to NEC ($1.78 M) for a FCCU with a feed rate of 60 thousand barrels, the costs of waste heat boiler ($4.5 M) estimated by NEC, the costs of CEMS ($1.5 M) estimated by NEC, the costs of ammonia storage tank ($1.5 M) estimated by NEC, and annual operating costs estimated by NEC.

The PWV for the manufacturer's design with no markup ($21 M) was only 10% more than staff's estimates using the EPA methodology. With equivalent markup factors applied, the manufacturer's 2-layer model was approximately 22 percent lower in cost than the 3-layer model. This compares well with the 26 percent PWV adjustment between the NEC 3-catalyst layer model and staff's estimate for the 2-layer SCR noted for Refinery 1 in Approach #1. Also, for the EPA methodology, staff used a 50% contingency factor to account for the uncertainty in the complex refinery environment compared to the EPA OAQPS Guidelines recommended a level of 30%.

The cost curve described in Approach #2 was used estimate the PWV of the SCR system with two NEC markup factors for an SCR provided by vendor with 2 layers of catalysts, a new waste heat boiler, a new CEMS, and a new ammonia storage tank. The curve was applied to the boiler FCCU feed rates to estimate the PWVs of five SCRs at the refineries are listed in Table F.3.

Table F. 3 - Comparison of Cost Estimates for SCRs with and without Markups

	Feed Rate (10^3Barrels per Day)	AQMD's Estimates PWV ($M)	Manufacturer's costs with 2 layers of catalysts and 2 levels of markups $PWV = 2.8013*(\text{Feed Rate})^{0.6}$ ($M)
Ref 5	71	33	36
Ref 6	90	57	42
Ref 7	55	27	31
Ref 4	34	16	23
Ref 9	55	19	31
Total		**152**	**163**

Summary of NEC's Approach

NEC based their estimation of PWV on a manufacturer's detailed cost profile for a 3-bed SCR for Refinery 9 where 2 layers were designated for catalyst loading. NEC's preferred engineering design required 3 catalyst layers (4-bed design with on bed in reserve) to meet the 2 ppmv emissions level. As such, the manufacturers design was scaled upward based on additional catalyst volume and associated costs as well as adjustments to the space velocity. The revised design was then subjected to the same cost assumptions stated in staff approach #2. PWV was estimated for the several feed rates to establish a distribution that was the basis for a power law cost curve. (See Addendum-1 to the staff report for NEC's analysis).

During the review of the NEC report, it was noted that the initial feed rates used by NEC in estimating PWV were not consistent with reported levels (Table F.4).

Table F. 4 - Refinery Feed Rates of FCCUs in SCAQMD

Refinery No.	**4**	**7**	**9**	**5**	**6**
Back-calculated feed rates used by NEC, 10^3 Barrels/Day	58	68	60	79	79
Feed rates reported in SOx RECLAIM, 10^3 Barrels/Day	30	55	55	71	90
Feed rates shown in the Jan 22 14 Working Group Meeting, 10^3 Barrels/Day	34	49	52	67	84

- The NEC 3-layer SCR model PWV estimates were recalculated using the reported feed rates and the revised PWVs were reduced by 26% to reflect the difference between the NEC cost curve estimate for Refinery 1 and the PWV determined by staff in Approach #1 above using the reported data.

- A comparison of the revised NEC cumulative PWVs adjusted by the 26 percent factor (2 vs. 3 catalyst layers for Refinery-1) with the staff approach #1 methodology were in good agreement (Table F.5).

Table F.5 – Estimates of Costs Adjusted to Refinery Feed Rates and Using the Refinery 1 26 Percent PWV Adjustment

	Feed Rate (10^3 Barrels/D)	Staff's Estimates ($M)	Revised NEC Estimates ($M)	Ratio Revised NEC/Staff's Estimates
Ref 5	71	33	34	1.03
Ref 6	90	57	40	0.70
Ref 7	55	27	29	1.07
Ref 4	34	16	22	1.38
Ref 9	55	19	29	1.53
Total		**152**	**154**	**1.01**

Summary of the Analysis

Staff based its cost estimates on the application of a 2-catalyst layer SCR design for each of the refineries. The analysis focused on Refinery 1 which had achieved in practice an emissions level of 2 ppmv with the 2-catalyst layer design.

NEC recommended a more conservative 3-catalyst layer design based upon their experience with refinery controls installations.

Both designs have nearly equivalent estimated PWV when the 3-to-2 catalyst layer assumption is normalized.

The costs estimated by staff provide a CE range between $18K and $20 K per ton of NOx reduced. Using the NEC 3-Layer approach, the upper value of CE would be $29K.

Appendix G - Comparative Analyses for Boilers & Heaters

This appendix provides a comparison of the control equipment design configuration, total installed cost (TIC) calculation and present worth Value (PWV) estimation used in the staff and NEC estimations for the boiler and heater cost effectiveness calculation. Table G.1 summarizes the basic comparison. Variations in the selective catalytic reduction (SCR) size, cost assumptions and TIC and PWV estimation methodology are provided in a side by side comparison for evaluation. As previously stated in Appendix B, the NEC design to reach 2 ppmv relies on the use of 3 layers of catalyst and 1 additional layer for an Ammonia Slip Catalyst (ASC) bed. Staff's estimate is based on existing SCR applications achieved-in-practice and alternate control methodologies identified in the analysis.

Table G.1 - Comparison of Staff and NEC Control Equipment Designs, TIC and PWV Estimation Methods

	Staff's Design	**NEC's Design**
SCR Configuration	1-Catalyst layers	3-Catalyst layers 1-ammonia bed 4-Beds: all used
Alternate Configurations	Great Southern Flameless Heaters ClearSign Duplex burners	
Cost Models	Refinery survey data, refinery consultant's data, cost estimates from SCR manufactures, Great Southern and ClearSIgn were used to construct maximum PWV of SCRs for 5 ppmv NOx for 5 ranges of boiler/heater firing rates.	SCR Vendor Based application (scaled for 4-layers) with NEC modifications and refinery input. Additional cost for induced draft fan
	CPWV of SCRs for 2 ppmv NOx = 1.1 * PWV of SCRs for 2 ppmv emissions limit for 5 ranges of boiler/heater firing rates	Individual PWV Costs curves for 5 ppmv and 2 ppmv emissions limits based on maximum firing rate
Refinery Application	83/212 Units ≤ $50,000/Ton	46/212 Units ≤ $50,000/Ton

Summary of Staff's Approach

- Cost data for all feasible control technologies including SCRs, LoTOx, Great Southern flameless heaters, and ClearSign duplex burners was analyzed.

- Three sets of cost data were used to construct the cost curve in Figure G.1:

    - Group 1 data set: Survey cost data provided directly by the refineries for SCRs that achieved 1.6 – 3.5 ppmv NOx was used. The refineries provided actual equipment costs, total installed costs (TIC) and annual operating costs. The actual costs were increased to 2014 dollars. From this set of actual costs: TIC = 3.87 x equipment costs, and PWV = 1.052 x TIC = 4.07 x equipment costs.

- Group 2 data set: Cost data estimated by the consultants for a refinery for future SCR projects was used. The consultants of the refinery applied a factor of 4.0 to estimate TICs for future projects (i.e. TIC = 4.0 x equipment costs), and staff estimated the PWVs consistently with the actual cost data in Group 1, PWV = 1.052 x TIC.

- Group 3 data set: Equipment costs provided by control equipment manufacturers for SCRs, Great Southern Flameless heaters, and ClearSign Duplex burners were used. TICs were estimated using a factor of 4.0, and PWVs were estimated using a factor derived from the Group 1 data set.

- Staff selected the upperbound PWVs shown in Figure G.1 for the costs of control devices that can achieve 5 ppmv NOx. Staff added another 10% to the upperbound costs in Figure 1 to derive the costs for control devices that can meet 2 ppmv NOx:

  $5.5 M for units with maximum rating ≤ 100 mmBtu/hr
  $11 M for units with maximum rating > 100 – 200 mmBtu/hr
  $22 M for units with maximum rating > 200 – 400 mmBtu/hr
  $33 M for units with maximum rating > 400 – 600 mmBtu/hr
  $49.5 M for units with maximum rating > 600 mmBtu/hr

The upperbound PWVs derived were higher than all of the actual costs from the Group 1, 2 and 3 data sets. For example, the actual reported costs for a 650 mmBtu/hr heater was about $42 M and the upperbound PWV that staff derived based on this approach was $49.5 M.

Summary of NEC's Approach

NEC concurred that the 2 ppmv BARCT level is feasible for refinery boilers/heaters >40 mmBtu/hr. However, NEC stated their recommendation required using SCRs with 4 layers of catalysts [3-layers plus 1-layer of ammonia slip catalyst (ASC)].

- NEC used the approach described in Appendix F whereby a manufacturers design and quote for a 2-catalyst layer SCR (with 1-additional bed) was structured to accommodate a 4-layer SCR with 3-catalyst layers and an ammonium slip catalyst layer. Their estimate also included costs for a new CEMS, ammonia system and induced draft fan installation.

- NEC adjusted the manufacturer's design to 10 ft/sec velocity, increased the cross section area, added a 3rd and a 4th layer of catalysts, increased the SCR dimension to 20 feet width x 19.2 feet length x 44 feet height, and increased the equipment costs to $2.48 M.

NEC estimated annual costs for ammonia usage, utility, catalyst replacement, and miscellaneous maintenance and developed 2 sets of PWV cost curves based on applying the NEC SCR model to a range of firing rates.

The PWVs were estimated by NEC as follows:

PWV = 3.1354 x (Maximum rating of boiler or heater) $^{0.3947}$ for 5 ppmv SCRs
PWV = 3.4838 x (Maximum rating of boiler or heater) $^{0.3947}$ for 2 ppmv SCRs.

NEC provided two curves for 2 ppmv SCR and 5 ppmv SCR that staff could use to estimate the incremental costs for boilers/heaters >110 mmBtu/hr. Figure B.3 is revised below (Figure G.1) to include the NEC cost curves. The difference in the cost curve PWV project is most pronounced for the smaller units with maximum firing rates 200 mmBtu or less. As the firing rate increases beyond 500 mmBtu, the curves begin to converge.

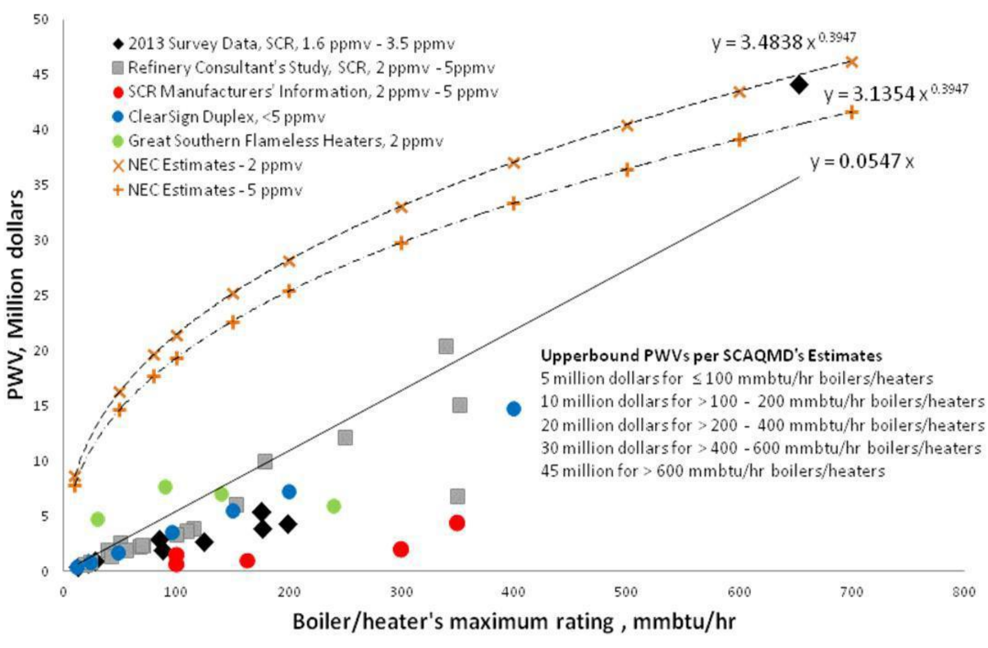


Figure G. 1 - Present Worth Values for SCRs (December 2014)

Summary and Discussion

The two methodologies employed to develop the PWVs for SCRs are inherently different. The resulting number of units determined to be cost effective at 2 ppmv NOx at an under $50,000 per ton threshold varied from 48 using the NEC method to 103 units using the staff method. Using the NEC method resulted in 0.33 TPD less NOx reductions. As is noted in the following discussion, SCRs have achieved-in-practice 2 ppmv NOx in the Basin using the 1-catalyst layer SCR model. As a consequence of the uncertainty in PWV between the use of the two cost methodologies and CE estimation, staff is proposing to reduce the overall RECLAIM RTC reductions by the 0.33 TPD as a component of the overall adjustment from 14.8 to the 14.0 TPD proposal.

There are several heaters in the SCAQMD that have SCRs built to achieve 5 pppmv NOx, and these SCRs actually achieved 1.6 ppmv – 2.7 ppmv as reported by the refineries. All of these SCRs have 1 layer of catalysts. The catalyst depth is about 2 – 3 feet, and the catalyst volumes range from 62 – 623 cubic feet as shown in Table G-2. By comparison, the Refinery 1 FCCU SCR has 2 layers of catalyst with a total catalyst depth of 9 feet. The dimensions of the Refinery 1 FCCU SCR listed in Table G.2 are compared to the dimensions of the existing SCRs for refinery heaters. Refinery heater SCRs are more compact with smaller volumes of catalysts compared to FCCU SCRs. In contrast, Refinery 1 FCCU's feed rate is about 95,000 barrels per day (B/D) yet Refinery 1 FCCU SCR achieved less than 2 ppmv NOx using only 2-catalyst layers.

Table G. 1 – Performance Levels and Dimensions of Existing SCRs for Heaters in SCAQMD Compared to Existing SCR for an FCCU

	Ref 9 3 hydro treating heaters	Ref 5 isomax heater	Ref 5 crude heater	Ref 9 crude heater	Ref 5 3 coker heaters	Ref 5 4 ref-ormers	Ref 1 FCCU
Maximum rating, mmbtu/hr	63	78	83	85	528	589	95,000 B/D
NOx, survey, ppmv	**2.7**	**2.3**	**2.7**	**3.3**	**2.7**	**1.6**	**< 2ppmv**
NOx, permit limit, ppmv	n/a	5	5	5	n/a	5	
SCR, Width, ft	5	20	4	17	18	13	30
SCR, Length, ft	6	7	6	7	18	16	29
SCR, Height, ft	4	6	3	12	20	3	49
Total SCR volume, ft3	110	798	note 1	1,380	6,300	note 1, 2	41,748
Existing catalyst volume, ft3	92	92	62	96	623	537	**6,210**
No of catalyst layers	1	1	1	1	1	1	**2 (1 spare)**
Catalyst depth, ft	3	2	3	2	2	3	**4.5**

Note:

1) The SCR height stated in the permit is likely for the catalsyts and not for the overall SCR .

2) District recently approved a change of catalysts for this SCR. New catalyst volume is 424 ft3, guarantee of <=5 ppmv NOx

Appendix H - Comparative Analyses for SRU/TGUs

This appendix provides a comparison of the proposed control equipment design configuration, total installed cost (TIC) calculation and present worth Value (PWV) estimation used in the staff and NEC estimations for the SRU/TGTU cost effectiveness calculation. Table H.1 summarizes the basic comparison. Staff evaluated selective catalytic reduction (SCR), LoTOx, and Know-NOx technologies while NEC expressed concerns on the effectiveness and applicability of technologies other than SCR. Where comparable, variations in the SCR size, cost assumptions and TIC and PWV estimation methodology are provide in a side by side comparison for evaluation.

Table H-1 - Comparison of Staff and NEC Control Equipment Designs, TIC and PWV Estimation Methods

	Staff's Design	NEC's Design
SCR Configuration	1-Catalyst layer 2	3-Catalyst layers 3-Beds: all used
Alternate Configurations	LoTOx ozone injection coupled with either a Belco EDV or DynaWave scrubber Know-NOx ClO2 injection coupled with a DynaWave scrubber	N/A N/A
Additional Equipment	Heat Exchanger	Waste heat boiler (heat exchanger)
Cost Models	Cost estimates: SCR manufacturers LoTOx and Know-NOx PWV estimated using EPA format (1.86 TIC) with 1.5 contingency factor Costs revised to reflect NEC PWV 4.5 factor	SCR Vendor Based application (scaled for 3-layers) with NEC modifications and refinery input.
Refinery Application	9 Units ≤ $50,000/Ton	9 Units ≤ $50,000/Ton

Summary of Staff's Approach

- Cost data for all feasible control technologies including SCR, LoTOx, and KnowNOx were analyzed. SCR and LoTOx are used in refinery applications such as boilers, heaters, and FCCU while KnowNOx currently does not yet have any refinery application.

- Process information for three representative scenarios was sent to 2 SCR manufacturers, MECS (LoTOx), and KnowNOx. Cost data provided by the manufacturers using the EPA

OAQPS Guideline methodology were used to estimate the TIC. This approach was used in the 2005 RECLAIM rule amendment.

Instrumental = 10% x Equipment costs
Sales Tax = 9% x Equipment costs
Freight = 5% x Equipment costs
Total Equipment Costs = 1.24 x Equipment costs
Installation = 50% x Total Equipment Costs
Total Installation Costs = (1.5) x Total Equipment Costs = 1.5 x 1.24 x Equipment Costs = 1.86 x Equipment Costs

- The SCR manufacturers also provided other pertinent information such as the SCR overall dimension and the number of catalyst layers needed to achieve 2 ppmv for a SRU/TG incinerator application.

- A contingency factor of 1.5 was used to cover any uncertainty in the estimated costs.

Summary of NEC's Approach

As previously described in Appendix F, NEC based their estimation of PWV on a manufacturer's detailed cost profile for a 3-bed SCR where 2 layers were designated for catalyst loading. NEC's preferred engineering design required 3 catalyst layers (4-bed design with one bed in reserve) to meet the 2 ppmv emissions level. As such, the manufacturr's design was scaled upward based on additional catalyst volume and associated costs as well as adjustments to the space velocity. The revised design was then subjected to the cost assumptions stated in staff approach #2. PWV was estimated for the several feed rates to establish a distribution that was the basis for a power law cost curve. (See Addendum-1 to the staff report for NEC's analysis).

Summary

The staff and NEC approach to estimate the control costs differ. Addendum-1 of the Staff Report provides NEC's non-confidential "SCAQMD NOx RECLAIM – BARCT Feasibility and Analysis Review". A major difference between the two assessments revolves around the selection of control equipment analyzed. The SCAQMD analysis included multiple control technologies while NEC analysis relied solely on SCR implementation where design options and costs were prorated for the SRU/TG applications. Additionally, costs associated with CEMS, ammonia storage tanks and heat exchangers account for differences between the initial staff and NEC cost estimates. Note that the different approaches do not have an impact on the list of equipment that meet the $50,000 per ton cost effectiveness threshold for inclusion in the calculation of potential BARCT emission reductions from SRU/TGUs.

A second major difference between the two assessments occurs in the costing methodology to estimate TIC and PWV. Staff's use of the EPA methodology with a 1.5 contingency factor markup to estimate PWV is lower than the combined bid conditioning, labor adjustment and 4.5 installation mark-up used by NEC. (It is important to note that separate discussions with refiners and their consultants indicated that a mark-up factor of 4.0 or greater may be more representative).

As stated in Appendix E, in their final assessment, staff revised its cost estimate to reflect the higher TIC to PWV cost factor proposed by NEC which resulted in closing the gap between the two analyses.

Appendix I - Comparative Analyses for Coke Calciners

This appendix provides a comparison of the NOx emissions control design configuration, total installed cost (TIC) calculation and present worth Value (PWV) estimation used in the staff and NEC estimations for the Coke Calciner cost effectiveness calculation. Table I.1 summarizes the basic comparison. Variations in the equipment design, cost assumptions and TIC and PWV estimation methodology are provided in a side by side comparison for evaluation.

Table I.1 Comparison of Staff and NEC Control Equipment Designs, TIC and PWV Estimation Methods

	Staff's Design	**NEC's Design**
Proposed Control	LoTOx or UltraCat	LoTOx with modifications: taller or larger diameter scrubber, two vessels to enhance dry time, additional ozone usage and multiple ozone injection points
Target Emissions Limit	2 ppmv	5- 10 ppmv
Cost Basis	LoTOx TIC and UltraCat equipment costs provided by manufacturers	LoTOx equipment costs provided by manufacturers
	LoTOX PWV calculated by multiplying a 1.5 contingency factor to TIC and annual operating costs. UltraCat TIC estimated using the U.S. EPA 1.86 factor. PWA calculated by multiplying a 1.5 contingency factor to TIC and annual operating costs	TIC estimated as 1.35 factor applied to equipment cost to account for NEC proposed modifications. PWV calculated by multiplying a 3.44 contingency factor to TIC and annual operating costs

Summary of Staff's Approach

In order to collect cost data for all feasible control technologies, including LoTOx and UltraCat systems, staff sent the process information to the manufacturers, and the manufacturers provided equipment costs, annual operating costs, and foot print of the control devices. Staff used the approach in the EPA OAQPS Guidelines to estimate the Total Installed Costs (TIC = 1.86 x Equipment Costs.) This approach was used in the staff report of the 2005 RECLAIM rule amendment. Costs were increased by 50% to cover any uncertainty in the estimated TIC and annual operating costs.

Summary of NEC's Approach

NEC proposed 5 to 10 ppmv for BARCT. NEC used the costs provided to staff, and applied a factor of 4.67 to cover uncertainty in process development and installation costs. As a result, TIC = 4.67 x Equipment costs. Ultra-Cat was not considered a solution for the coke calciner.

Summary

Staff agrees that the coke calciner is a challenging application, and the BARCT level should be set at 10 ppmv as recommended by NEC. Addendum-1 of the Staff Report provides NEC's non-confidential "SCAQMD NOx RECLAIM – BARCT Feasibility and Analysis Review". Staff also agrees that a factor higher than the EPA OAQPS's factor of 1.86 would be reasonable for the coke calciner because of the space congestion situation at the site. Staff revised the calculation and used a factor of 4.5 instead of 1.86 for both LoTOx and Ultra-Cat technologies.

Appendix J - Comparative Analyses for Turbine/Duct Burners

This appendix provides a comparison of the control design configuration, total installed cost (TIC) calculation and present worth Value (PWV) estimation used in the staff and NEC estimations for the Turbine/ Duct Burner cost effectiveness calculation. Table J.1 summarizes the basic comparison. The cost assumptions for TIC and PWV estimation methodology are provided solely for the staff proposal since NEC recommendation was to add catalyst to achieve the 2 ppmv targeted emissions limit.

Table J.1 - Comparison of Staff and NEC Control Equipment Designs, TIC and PWV Estimation Methods

	Staff's Design	NEC's Design
Control Devise Configuration	Install new SCR with Ammonia Slip Catalysts and/or add catalyst to existing SCRs	Add catalyst to existing SCRs
Cost Basis	Cost information provide by several sources: • SCR costs directly provided by Refineries 1 and 10; • Costs also provided by vendor for SCR • US EPA SCR cost estimate from literature • Cheng Low NOx technology	Costs information provided by vendor and Refinery 1
Cost Models	Cost curve relating PWV to MW	Cost curve relating PWV to MW

Appendix K – Co-Benefits of Energy Efficiency Projects

Table K.1 below summarizes NOx reductions that are expected to occur as co-benefits of energy efficiency projects undertaken by the refineries in the Basin from the California Air Resources Board (CARB)'s report "Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources – Refinery Sector Public Report, June 6, 2013.

CARB approved the Energy Efficiency and Co-Benefit Assessment of Large Industrial Facilities (EEA Regulation) on July 22, 2010. The regulation required the largest industrial sources in California to conduct a one-time assessment of fuel and energy consumption, and emissions of greenhouse gas, criteria pollutants, and toxic air contaminants. Affected facilities were also required to identify potential improvements in equipment, processes, or systems that could result in energy savings. http://www.arb.ca.gov/cc/energyaudits/energyaudits.htm#background.

CARB has a three-phase implementation plan to implement the EEA Regulation. Phase 1 was to develop the industrial sector public reports. From June 2013 to April 2015, CARB released five separate public reports compiling the information provided by the facilities subject to the EEA Regulation. The first report released in June 2013 was for the refinery sector. CARB is working on Phase 2 to develop the findings report, and Phase 3 to develop the Energy Efficiency Implementation Program. http://www.arb.ca.gov/cc/energyaudits/publicreports.htm.

CARB staff indicated that currently there was no requirement for the refineries to report the emissions stated in the public report released in June 2013 for inventory purposes. In addition, CARB had no process by which the inventory could be modified based on the estimates provided in the report. CARB did not know if the actual emission reductions would be different from the estimates in the report, and CARB had no plan to count these estimates as reductions to the current air quality. Thus, staff did not count the reductions in this proposal.

Table K. 1- Summary of Emission Reductions and Schedules of Energy Efficiency Projects

Facility	Completed/Ongoing Projects Completed Before 2011 (tpd)			Scheduled Projects After 2011 (tpd)	Under Investigation Projects After 2011 (tpd)		**Total (tpd)**	
	Range		Completion Date		Range		**Range**	
BP-Carson (Table II-4)	0.064	0.064	2009-11	0.014	0.019	0.019	**0.097**	**0.097**
Chevron El Segundo (Table II-9)	0.054	0.088	2007-11	0	0	0	**0.054**	**0.088**
Phillips66 Carson (Table II-17)	0	0.026	2008-11	0	0	0.013	**0**	**0.039**
Phillips66 Wilmington (Table II-21)	0	0	2009-11	0	0	0.013	**0**	**0.013**
ExxonMobil Torrance (Table II-29)	0.204	0.204	2008-11	0.036	0	0	**0.24**	**0.24**
Tesoro Los Angeles (Table II-37)	0.221	0.221	2009-11	0	0.049	0.049	**0.27**	**0.27**
Valero Wilmington (Table II-46)	0.056	0.056	2007-10	0	0	0	**0.056**	**0.056**
TOTAL (tpd)	0.6	0.7		0.1	0.1	0.1	**0.7**	**0.8**

Reference: Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources - Refinery Sector Public Report, June 6,

Note:

BP Carson identified 21 projects completed in the 2009-11 time frame (p.35)

Chevron identified 27 projects completed in the 2007-11 time frame (p. 38)

Phillips66 Carson identified 8 projects completed in the 2008-11 time frame (p. 44)

Phillips66 Wilmington identified 7 projects completed in the 2009-11 time frame that reduced 0 tpd NOx (p. 47)

ExxonMobil identified 25 projects completed in the 2008-2011 time frame (p.53)

Tesoro identified 11 projects completed in 2009-11 time frame (p.59)

Valero identified 13 projects completed in 2007-2010 time frame (p.65)

Appendix L – Survey Questionnaires for Refinery Sector

In June 2013, staff developed Survey Questionnaire to collect pertinent information for the NOx RECLAIM rule development. The Survey Questionnaire was sent to the 37 top emitting facilities and California Portland Cement Company which was the #1 NOx emission source in the Basin in 2008. The Survey Questionnaire for the refinery sector and the non-refinery sector are shown below.

South Coast Air Quality Management
2013 NOx RECLAIM
Survey Questionnaire for Refineries
(Due Date: July 12, 2013)

Facility Contact

1. Please provide the facility contact for this project:
   Name: ________________________________
   Title: ________________________________
   Phone Number: _________________________
   Email Address: _________________________

Top NOx Emitting Equipment or Processes

(* The attached list may contain the information requested)

2. * Please verify the attached list for the top 10 NOx emitting equipment and processes at your facility in Compliance Year 2011 and their emissions.

3. Please mark on the attached list the NOx control equipment installed **after the 2005 NOx RECLAIM amendment**

Boilers, Heaters, Furnaces, Kilns, Turbines, and Cogeneration Units (Major and Large Sources)

4. For each major and large combustion source at your facility, please verify the following information in the attached list, and provide information if the attached list does not contain this specific information:
   a. * Device description, Device ID, Process Name
   b. * Emissions in CY 2011 (tons per day)
   c. * Maximum unit rating (MMBTU/hr)
   d. * Type of fuel used
   e. Fuel usage rate and BTU content of fuel
   f. Flue gas flow rate (million dry standard cubic feet), temperature, oxygen and water content

g. Representative flue gas analysis and fuel gas analysis
h. NOx concentration in the exhaust flue gas (ppmv at 3% O_2 or ppmv at 15% O_2). Please attach a copy of the most current source test reports/results.
i. Allowable back pressure
j. * Control technology used (e.g. LNB, SCR, NOx scrubber)

5. For the control technology identified in item #4 above:
   a. Device description, Device ID
   b. Manufacturer’s name and performance. Please attach a copy of manufacturer's specification/guarantee
   c. Design parameters (e.g. maximum flue gas flow rate, inlet and outlet ppmv, ammonia slip)
   d. If the control device is shared between multiple NOx emitting sources, please identify all other sources that are vented to this control device
   e. Dimension of the add-on NOx control device (e.g. length, width, height of the SCR, catalyst volume)
   f. Cost information (capital costs, installation costs, and annual operating costs)
   g. Installation date (e.g. July 2005)

6. Provide drawings that show location and distances between the major and large NOx sources at the facility.

Fluid Catalytic Cracking Units

7. If the facility currently uses NOx reduction catalysts, please provide:
   a. Manufacturer’s name
   b. Usage rate (e.g. lbs of catalysts added per day)
   c. Flue gas flow rate, temperature, oxygen, water content and flue gas analysis
   d. NOx in the exhaust flue gas (ppmv at 3% O2). Please attach a copy of the source test results
   e. Cost information (annual operating costs)

8. If the facility uses add-on NOx control device, please provide:
   a. Manufacturer’s name and performance. Please attach a copy of manufacturer's specification/guarantee
   b. Design parameters (max flue gas flow rate, temperature, oxygen, water content, flue gas analysis)
   c. NOx in the exhaust flue gas (ppmv at 3% O2). Please attach a copy of the source test report/results
   d. Dimension of the add-on NOx control device
   e. Cost information (capital costs, installation costs, and annual operating costs)
   f. Installation date (e.g. July 2005)

Reports Submitted Under the U.S. EPA Consent Decree

9. If the facility must install control technology to reduce the NOx emissions under an U.S. Environmental Protection Agency (EPA)'s consent decree, please provide the District a copy of the most recent reports/test results submitted to the EPA related to this consent decree.

Feasible Control Approach Including Energy Efficiency Project

10. List any feasible control approach that your facility plans to install, including replacement of the existing units with higher energy efficient units, to further reduce your facility's NOx emissions and green-house gases. Provide a brief description of the control approach, manufacturer's name, estimated emission reductions, and cost information.

If you have any questions, please contact either:
Minh Pham, P.E. (909) 396-2613, mpham@aqmd.gov, or
Gary Quinn, P.E. (909) 396-3121, gquinn@aqmd.gov

Please submit information via e-mail by July 12, 2013
to Minh Pham and Gary Quinn.
Thank you for participating in the Survey.

Part II – BARCT Analyses for Non-Refinery Sector

Part II contains the information related to the BARCT analyses for the non-refinery sector. Part II includes 7 Appendices from Appendix M to Appendix S that discuss 1) the NOx control technologies, 2) costs and cost effectiveness analyses for the NOx emitting sources at the top 27 non-refinery facilities, and 3) staff's review of the consultant's costs and cost effectiveness analyses. The Survey Questionnaires for non-refinery facilities are included in Appendix T.

Appendix M – Cement Kilns

Process Description

In the NOx RECLAIM program there is one facility that operates cement kilns. This facility, under normal operation, has typically been among the highest NOx emitters in the RECLAIM program. This facility produces gray cement from limestone, sand, shale, and clay raw materials. The raw materials are processed into a mix that is fed into a long, dry kiln that goes through pyroprocessing. Pyroprocessing transforms the fine raw mix into cement clinker through physical and chemical reactions inside the kiln. The facility operates two of these long, dry kilns that rotate slowly and are inclined at an angle. The raw materials are fed at the higher end of the kiln and proceed through it under the high heat of the combustion gases that are produced by the kiln burners at the lower end. Once the material exits the kiln, it is considered clinker and is cooled, and further processed (ground, milled) into cement. The combustion fuels used in these kilns include petroleum coke, natural gas and tire-derived fuel (TDF). The flue gases exiting the kilns are then ducted to individual waste heat boilers that operate a steam generator for electricity. After the waste heat boilers, the flue gases from each kiln go to a dedicated baghouse which separates the solid particulate. The resultant flue gases then exit from individual stacks.

In 2005, there was no new BARCT proposed for this source category. The emission factor has remained unchanged from the 2000 (Tier 1) Level, which is 2.73 pounds of NOx per ton of clinker produced.

Current Emission Inventory

There are two long, dry cement kilns located at the subject NOx RECLAIM facility. This facility was not in operation in compliance year 2011 due to decreased production and has not been in operation since. Therefore, for the purposes of calculating the BARCT reductions, the baseline emissions from the 2012 AQMP base year (2008) were used for the emission reduction determination and cost effectiveness calculation.

Table M. 1 - 2011 Emissions for Cement Kilns

Equipment Type (at Top 37 Facilities)	Number of Units	2008 Emissions (tpd)
Long, Dry Cement Kiln	2	1.61

Control Technology

Long, dry cement kilns have achieved NOx reductions to the 2000 (Tier 1) level by utilizing low NOx burners and mid kiln firing with tire-derived fuel (TDF). With TDF, whole tires are introduced at an inlet location about midway along the kiln's calcining zone. TDF lowers NOx emissions by lowering the flame temperatures and reducing thermal NOx with the introduction of a slower burning fuel.

The facility began testing one of the kilns with a selective non-catalytic reduction system (SNCR) before it ceased operation. This approach involves injecting ammonia directly into the kiln heating zone, where NOx reduction occurs without the utilization of a catalyst. With SNCR, the temperature window is critical for successful treatment of NOx. With a long, dry cement kiln, this is often difficult to achieve with the different temperature zones along its length and the necessity to inject the reagent mid-kiln. NOx treatment is easier to achieve on more modern preheater/precalcining kilns with SNCR since they are often shorter in length and the temperature window lies towards the exit of the kiln at the lower part of the preheater tower. This allows for readily feasible reagent introduction. The testing of the SNCR system at the facility yielded about a 30% NOx reduction. As applied to other kilns, SNCR is capable of achieving between a 30 and 50% NOx reduction. In the case of this facility, a 45% NOx reduction would result in meeting the New Source Performance Standard (NSPS) level of 1.5 pounds of NOx per ton of clinker produced. This emission level is equivalent to that of a new precalciner kiln using SNCR for NOx control.

After discussions with several vendors, there is more than one technology available for effective treatment of NOx from this source category beyond the Tier 1 level. To effectively achieve the most significant NOx reduction, selective catalytic reduction (SCR) is a proven technology that is well suited for the flue gas treatment of NOx. This technology uses a precious metal catalyst that selectively reduces NOx in the presence of ammonia. Ammonia is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of the catalyst to produce nitrogen and water vapor. The typical operating temperature of the exhaust gas is between 450 and 850 degrees F. In cement applications, the inherently high particulate load of the flue gas stream has created problems in the past for catalysts. The dust can plug the catalyst matrix openings and can also mask active sites which results in a degradation of performance. This obstacle can be overcome by utilizing sootblowers which blow off the accumulated particulates at timed intervals from the catalyst surface. There have been several installations of SCR systems on cement kilns in Europe that can handle high dust loads in the flue gas. The installation at Monselice, Italy has been in operation since 2006 and the installation at Mergelstetten has been in operation since 2010. An

SCR has also been installed on a long, dry kiln in Joppa, Illinois. It has been operating since 2013 and can achieve an 80% NOx reduction.
For cement applications, an alternate technology is available primarily for multi-pollutant control. The system utilizes Ultra Cat ceramic fiber filters. The flue gas is injected with ammonia that mixes with the gas and permeates across the ceramic filter wall. The filter material is embedded with catalyst which removes the NOx. Dry sorbent is injected in the flue gas to react with SOx. The resultant particulate, along with other particulate matter is captured at the outside of the filter walls.

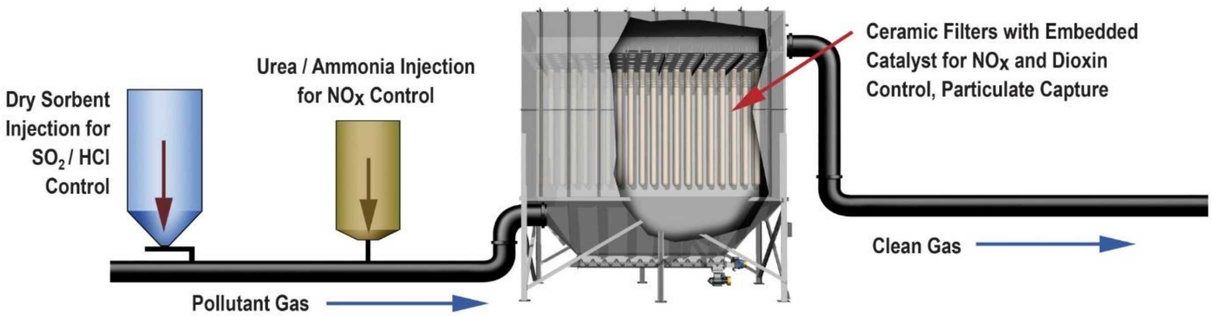


Figure M. 1 - Ultra Cat Ceramic Filter System

The accumulated solids on the filters are removed by a pulsed jet of air through the filter and the resultant solid waste is collected underneath the housing and is landfilled. This technology is guaranteed to achieve an 80% NOx reduction.

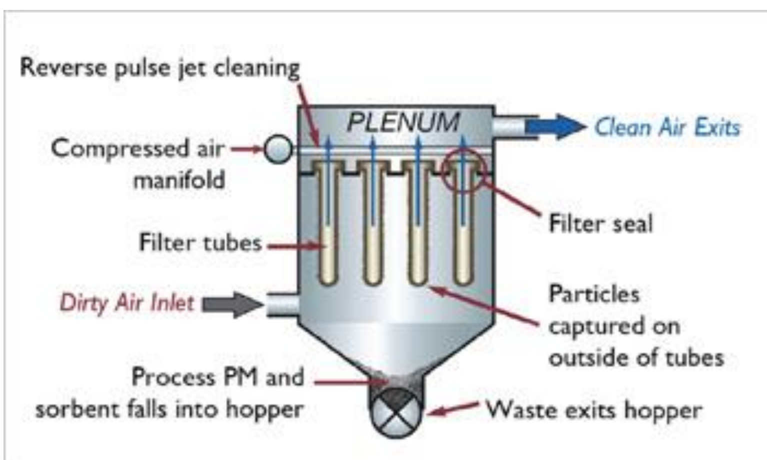


Figure M. 2 - Close-Up of Filter Housing and System Operation (Refernce #2)

Another multi-pollutant control option for cement kilns is also possible that would reduce SOx and PM with a wet gas scrubber and treat NOx with SCR. A wet gas scrubber uses a liquid solution, typically caustic, as the absorbing agent for SO_2. The absorbed SO_2 is converted to sulfates and sulfites which are then captured in the liquid effluent treatment system where they are separated and then disposed. Solid particulates in the flue gas stream are removed by impaction with the liquid droplets inside the scrubber. The outlet flue gas stream is then processed by the SCR system for removal of NOx. Temperature control is extremely important for proper functioning of the pollutant control systems, primarily for SCR. The gas has to be hot enough after being processed by the scrubber for SCR treatment. This can be achieved by utilizing a heat exchanger ahead of the scrubber to reheat the gas to the proper temperature for SCR treatment. In this configuration, the scrubbing unit is installed ahead of the SCR for the purposes of removing SO_2 and preventing the formation of ammonium bisulfate (ABS). ABS formation is a result of sulfur compounds reacting with ammonia from the SCR system at a lower temperature below the dew point. ABS formation is reversible, and this involves heating the catalyst to evaporate it. When SO_2 is present in the flue gas stream, the minimum SCR process temperature is determined by the formation of ABS. With the removal of SO_2 from the flue gas stream by the scrubber, however, ABS formation is not an issue when operating the SCR system at the lower end of the normal temperature range.

Proposed BARCT level and Emission Reductions

SCAQMD command and control Rule 1112 set NOx limits for gray cement kilns. Last amended in 1986, the rule limits NOx emissions to 6.4 pounds per ton of clinker produced, averaged over any 30 consecutive day period. The 2005 NOx RECLAIM amendment proposed no new BARCT for cement kilns, so these units have been only required to meet the Year 2000 Tier 1 emission level. The Tier 1 emission level for cement kilns is 2.73 pounds of NOx per ton of clinker produced. When they were in operation, the two units in the NOx RECLAIM universe of facilities were compliant with the Tier 1 NOx emission level.

Based on vendor discussions, the proposed BARCT level for gray cement kilns is an 80% reduction and the control technology to achieve the NOx reductions is SCR or the Ultra Cat ceramic filter system. This would result in an emission level of about 0.5 pounds of NOx per ton of clinker produced.

The emission reductions achieved from the two long, dry cement kilns, based on the 2008 compliance year baseline emissions, amount to 1.29 tons per day. This is the incremental reduction from the Tier 1 emission level.

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using vendor-supplied costs.

For an SCR installation on both kilns, the equipment costs include the SCR equipment, ductwork, steel, electrical, ammonia skid, sootblower air compressors, and insulation. The SCR system includes two layers of catalyst with a third layer for standby. A contingency value of 60% of the SCR equipment costs was estimated for the foundation civil work and other contingency. The SCR system for each kiln would be installed after the existing waste heat boiler and before the existing baghouse. This facility has specific plot space considerations that would require the installation of the SCR system between 5 and 30 yards from each waste heat boiler, depending on the kiln. The equipment would be placed on elevated platforms to allow for vehicle and/or railcar traffic underneath. There is no expected heat loss from the insulated ductwork. The annual operating costs include ammonia consumption and catalyst replacement costs, which for this installation were assigned a three year replacement interval.

For the Ultra Cat ceramic filter system, the equipment costs for both kilns include the emission control system, ammonia skid, booster fan, and engineering services, along with the installation. The annual operating costs include ammonia consumption, dry sorbent consumption, power consumption, labor, waste disposal, replacement filter costs. Since this facility is also a SOx source, dry sorbent injection for SOx removal will be required. This system would replace the existing baghouses at this facility.

The vendor-based equipment costs for the wet scrubber with heat exchanger and SCR for each kiln include the costs for the heat exchanger systems (ductwork, housing, dust collection hoppers), wet gas scrubber systems (venturi scrubber, pumps, structural steel, piping), and the SCR systems (2 layers of catalyst for each kiln, ductwork, ammonia skid, programmable logic control, sootblowers).

A contingency value of 60% of the equipment costs was estimated for the foundation and civil work, installation, and other contingency. The annual operating costs include ammonia consumption, catalyst replacement (3 year), caustic consumption, exhaust system fan power, scrubber pump power, and SCR dilution air fan and sootblower power. This system would replace the existing baghouses at this facility.

For all the scenarios, a present worth value (PWV) was calculated for the cement kilns using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

$$PWV = TIC + (15.622 \times AC)$$

A cost effectiveness value was then calculated for each case scenario using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This approach in calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

$$\text{Cost Effectiveness} = PWV / (ER \times 365 \times 25 \text{ years})$$

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

$$\text{LCF Cost Effectiveness} = (TIC \times CRF) + AC / (ER \times 365),$$

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

Table M. 2 - Cost Effectiveness for Cement Kilns

Vendor 1: SCR system installed between waste heat boiler and baghouse. NOx removal only.

Vendor 2: Dry scrubbing and ceramic filter system installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.

Vendor 3: Wet gas scrubber and SCR system with heat exchanger installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.

	Vendor 1	Vendor 2	Vendor 3
Capital Costs ($)	14,950,000	30,000,000	31,938,838
Annual Costs ($)	1,220,500	1,000,000	4,818,537
Present Worth Value ($)	34,016,651	45,622,000	107,214,017
Emission reductions (tpd)	1.287	1.287	1.287
DCF Cost Effectiveness ($/ton)	2,897	3,885	9,130
LCF Cost Effectiveness ($/ton)	4,635	6,216	14,609

To achieve an 80% NOx reduction, the cost effectiveness for cement kilns ranges from $2,900/ton to $9,100/ton ($4,600/ton to $14,600/ton, using LCF). Since the facility is also a SOx source, the calculated cost effectiveness combining NOx and SOx reductions equates to $3,300/ton for Vendor 2 and $7,600/ton for Vendor 3. This assumes a SOx reduction of 0.25 tons per day, as stated for the SOx RECLAIM amendment of 2010. All of the scenarios using the aforementioned NOx reduction technologies for flue gas treatment of cement kilns are considered cost effective.

Review of ETS's Analysis for Cement Kilns

ETS, Inc. was commissioned by SCAQMD staff to provide an independent evaluation of the previously described BARCT and cost analysis. ETS conducted a site visit at the facility to verify site specific considerations for the installation of control equipment.

For all the vendor installation estimates, a project scope contingency of 15% was applied to the total direct and indirect capital costs.

ETS concurs that there is sufficient plot space to install the control equipment for all three vendors and that an 80% NOx emission reduction is both feasible and cost effective.

Table M. 3 - ETS Revisions to Cost Effectiveness for Cement Kilns

Vendor 1: SCR system installed between waste heat boiler and baghouse. NOx removal only.

Vendor 2: Dry scrubbing and ceramic filter system installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.

Vendor 3: Wet gas scrubber and SCR system with heat exchanger installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.

	Vendor 1	**Vendor 2**	**Vendor 3**
	Staff's Estimate (ETS's Estimate)	Staff's Estimate (ETS's Estimate)	Staff's Estimate(ETS's Estimate)
Capital Costs ($)	14,950,000 (17,192,500)	30,000,000 (34,500,000)	31,938,838 (36,729,664)
Annual Costs ($)*	1,220,500	1,000,000	4,818,537
Present Worth Value ($)	34,016,651 (36,259,151)	45,622,000 (50,122,000)	107,214,017 (112,004,843)
Emission reductions (tpd)	1.287	1.287	1.287
DCF Cost Effectiveness ($/ton)	2,897 (3,088)	3,885 (4,268)	9,130 (9,538)
LCF Cost Effectiveness ($/ton)	4,635 (4,941)	6,216 (6,829)	14,609 (15,262)

* No revisions made by ETS

The facility made several comments regarding the BARCT analysis and staff conducted further research that resulted in a refinement of the cost analysis. Further communications with Vendor 1 revealed that the original estimate capital costs should have been doubled, as the previous costs were clarified as being for only one kiln. The facility had a concern over the temperatures at the exit of the waste heat boiler, before entering the control equipment. The facility provided an updated temperature which was 100 degrees below what had been provided previously and was below the normal operating temperature for normal SCR operation. To address this change, additional costs for reheating the flue gas were incorporated into the estimate, along with the natural gas costs to fuel the added duct burner. This updated system would utilize a natural gas-fired duct burner with a heat exchanger to reheat the gas approximately 100-150 degrees to enable the SCR catalyst to operate normally. The project contingency and other contingencies were adjusted to reflect the updated costs. The capital and operational costs for reheating the flue gas were applied to all three vendor estimates. In addition, operational costs were incorporated into the Vendor 3 estimate for wastewater treatment of the wet gas scrubber effluent. Furthermore, costs for powering new induced draft (ID) fans were also incorporated into the vendor estimates.

Table M. 4 - SCAQMD Revisions to Cost Effectiveness for Cement Kilns

Vendor 1: SCR system installed between waste heat boiler and baghouse. NOx removal only.			
Vendor 2: Dry scrubbing and ceramic filter system installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.			
Vendor 3: Wet gas scrubber and SCR system with heat exchanger installed after the waste heat boiler and replacing the baghouse. NOx, SOx, and PM removal.			
	Vendor 1	**Vendor 2**	**Vendor 3**
	ETS's Estimate (Staff's Estimate)	ETS's Estimate (Staff's Estimate)	ETS's Estimate (Staff's Estimate)
Capital Costs ($)	17,192,500 (37,812,000)	34,500,000 (38,400,000)	36,729,664 (42,166,606)
Annual Costs ($)*	1,220,500 (2,029,048)	1,000,000 (1,430,116)	4,818,537 (5,722,253)
Present Worth Value ($)	36,259,151 (69,509,788)	50,122,000 (60,741,272)	112,004,843 (151,559,636)
Emission reductions (tpd)	1.287	1.287	1.287
DCF Cost Effectiveness ($/ton)	3,088 (5,919)	4,268 (5,172)	9,538 (11,203)
LCF Cost Effectiveness ($/ton)	4,941 (9,471)	6,829 (8,276)	15,262 (17,927)

To achieve the proposed BARCT level, the revised cost effectiveness for cement kilns ranges from $5,200/ton to $11,200/ton ($8,300/ton to $17,900/ton, using LCF). All of these scenarios using the aforementioned NOx reduction technologies for flue gas treatment of cement kilns are considered feasible and cost effective.

References for Cement Kilns

1. Staff Report of Proposed Amendments to SOx RECLAIM. Agenda item 37 of the SCAQMD Governing Board Meeting. November 5, 2010.

2. *World's Largest Supplier of Ceramic Catalyst Filter Systems*. Tri-Mer Corporation Brochure, 2015; www.tri-mer.com.

3. *Ammonium Bisulphate Inhibition of SCR Catalysts*. Thogersen, J.; Slabiak, T.; White, N. Haldor Topsoe.

4. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

5. *The Costs and Benefits of Selective Catalytic Reduction on Cement Kilns for Multi-Pollutant Control.* Armendariz, A. Department of Environmental and Civil Engineering, Southern Methodist University. February 11, 2008.

6. *Elex CemCat's SCR Technology*. Elex Cemcat AG Presentation, March 2014; www.elex-cemcat.com/news_en/.

7. *Evaluation of NOx Control Options for CalPortland's Colton, CA Cement Kilns*. Schreiber, R.; Russell, C. Schreiber Yonley & Associates, July 2, 2013.

8. *Arizona Regional Haze and Interstate Visibility Transport Federal Implementation Plan, Final Rule*. United States Environmental Protection Agency, Region 9. October 3, 2014; EPA-R09-OAR-2013-0588-0072.

9. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

Appendix N – Container Glass Melting Furnaces

Process Description

In the NOx RECLAIM program there is one facility among the top 37 NOx emitting facilities that operates container glass melting furnaces. This facility produces container glass from dry, solid raw materials that are melted in the furnaces and then formed into glass container bottles.

In 2005, there was no new BARCT proposed for this source category. The emission factor has remained unchanged since 2000 (Tier 1), which is 1.2 pounds of NOx per ton of glass pulled.

Current Emission Inventory

There are two glass melting furnaces located at the subject NOx RECLAIM facility.

Table N. 1 - 2011 Emissions for Container Glass Melting Furnaces

Equipment Type	Number of Units	2011 Emissions (tpd)
Glass Melting Furnace (Container Glass)	2	0.30

Control Technology

Glass melting furnaces can achieve NOx reductions to the 2000 (Tier 1) level by utilizing oxy fuel firing. With oxy fuel firing, pure oxygen is used as the combustion reactant instead of nitrogen-laden ambient air. A higher temperature can be achieved for the batch melt based on the higher combustion efficiency in addition to achieving lower NOx emissions.

There is more than one technology available for effective treatment of NOx from this source category. To effectively achieve a significant NOx reduction, selective catalytic reduction (SCR) is a proven technology that is well suited for the flue gas treatment of NOx. This technology uses a precious metal catalyst that selectively reduces NOx in the presence of ammonia. Ammonia is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of the catalyst to produce nitrogen and water vapor. The typical operating temperature of the exhaust gas is between 450 and 850 degrees F.

For glass melting applications, an alternate technology is available that has been achieved in practice, primarily for multi-pollutant control. The system utilizes Ultra Cat ceramic fiber filters. Please refer to Appendix M for further details. This technology is guaranteed to achieve an 80% NOx reduction and has been installed or is under construction at 12 glass manufacturing locations worldwide.

Proposed BARCT level and Emission Reductions

SCAQMD command and control Rule 1117 set NOx limits for glass melting furnaces. Last amended in 1984, the rule limits NOx emissions to 4.0 pounds per ton of glass pulled, effective in 1992. The 2005 NOx RECLAIM amendment proposed no new BARCT for container glass melting furnaces, so these units have been only required to meet the Year 2000 Tier 1 emission level. The Tier 1 emission level for container glass melting furnaces is 1.2 pounds of NOx per ton of glass pulled. The two units in the NOx RECLAIM universe are currently compliant with the Tier 1 emission level.
Based on vendor discussions, the proposed BARCT level for container glass melting furnaces is an 80% reduction and the control technology to achieve the NOx reductions is SCR or the Ultra Cat ceramic filter system. This would result in a NOx emission rate of 0.24 pounds per ton of glass pulled.

The emission reductions achieved from the two container glass melting furnaces, based on the reported value of emissions, amount to 0.24 tons per day. This is the incremental reduction from the Tier 1 emission level of 1.2 pounds of NOx per ton of glass pulled.

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using vendor-supplied costs and the costs provided by the facility.

For the Ultra Cat ceramic filter system, the equipment costs were scaled from an existing vendor-based installation quotation for a sodium silicate glass melting furnace. The equipment costs which include the emission control system, ammonia skid, and booster fan were scaled by the heat input rate to the 0.6 power based on general chemical engineering cost estimating practice. The installation costs were calculated to be 40% of the equipment costs. The cost of installation as well as the cost of engineering services was scaled by the heat input rate. The annual operating costs (also scaled by heat input rate) include ammonia consumption, dry sorbent consumption, power consumption, labor, waste disposal, replacement filter costs. Since this facility is also a SOx source, dry sorbent injection for SOx removal will be required. This system would replace the existing dry scrubbing system and electrostatic precipitators (ESPs) at this facility.

For an SCR installation, two scenarios were considered. In the first scenario, one SCR chamber would handle the exhaust streams from the three ESPs. At this facility, three ESPs handle the exhaust from the two glass melting furnaces in which one ESP is operated as a backup. In the second scenario, one SCR would handle the exhaust from each ESP, so there would be a total of three SCR systems installed.

The vendor-based costs for the first option include the engineering, fabrication and field installation of a single SCR chamber sized to handle the exhaust from both furnaces. The SCR system includes one layer of catalyst with extra space for a second layer, supporting structure, ammonia skid, and programmable logic control (PLC) system. A contingency value of 80% of the SCR equipment costs was estimated for the foundation and ductwork to and from the existing stacks. This facility has specific plot space considerations that would require the installation of the SCR system roughly 30 yards from the ESPs and roughly 15 yards back to the stacks. The equipment would be placed on an elevated platform above the existing rail line. The annual operating costs include ammonia consumption and catalyst replacement costs, which for this installation were conservatively assigned an annual replacement interval. In addition, a 20% contingency was added to the annual costs for freight and installation.

The vendor-based costs for the second option include the engineering, fabrication and field installation of three SCR chambers as described for the first option, each sized to handle the exhaust from one furnace. A contingency value of 150% of the SCR equipment costs was estimated for the foundation and ductwork to and from the existing stacks. The annual operating costs were also derived as described for the first option. This option also included an additional 20% contingency.

The facility also provided an estimate for the retrofitting of one furnace that was based on the EPA cost manual for SCR installations for NOx removal. To expand this singular case to address the remaining furnace, two scenarios were considered for this approach. The first option would include the installation of two SCR systems, each sized to handle the exhaust of one furnace, manifolded to the existing three ESPs. The second option would include the installation of three SCR systems, each sized to handle the exhaust of one furnace. Each SCR would handle the exhaust from each ESP. For each option, the costs for additional SCRs were calculated by multiplying the facility-provided costs for a single unit with number of additional units required for each of the two options. Also for each option, a 15% contingency factor was applied to the direct and indirect costs. The annual operating costs for each option include operations and maintenance labor/materials, ammonia consumption, power consumptions and catalyst costs. In addition, an indirect annual cost factor was added and was calculated to be the capital costs multiplied by the capital recovery factor (CRF) for a 25 year installation at a 4% interest rate.

For all the scenarios, a present worth value (PWV) was calculated for the glass melting furnaces using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

$$PWV = TIC + (15.622 \times AC)$$

A cost effectiveness value was then calculated for each case scenario using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This approach in calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

$$\text{Cost Effectiveness} = PWV / (ER \times 365 \times 25 \text{ years})$$

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

$$\text{LCF Cost Effectiveness} = (TIC \times CRF) + AC / (ER \times 365),$$

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

Table N. 2 - Cost Effectiveness for Container Glass Melting Furnaces

Vendor 1: Dry scrubbing and ceramic filter system installed after the furnaces, replacing the dry scrubber and ESP. NOx, SOx, and PM removal.					
Vendor 2: SCR system installed post ESP. NOx removal only. Option 1: single chamber. Option 2: three chambers.					
Vendor 3: SCR system installed post ESP using costs provided by facility per EPA cost Manual. NOx removal only. Option 1: two chambers. Option 2: three chambers.					
	Vendor 1	**Vendor 2 Option 1**	**Vendor 2 Option 2**	**Vendor 3 Option 1**	**Vendor 3 Option 2**
Capital Costs ($)	5,134,891	2,070,000	5,000,000	4,096,959	6,145,439
Annual Costs ($)	567,686	132,500	180,750	560,123	840,185
Present Worth Value ($)	14,003,287	4,139,195	7,823,677	12,847,207	19,270,811
Emission reductions (tpd)	0.24	0.24	0.24	0.24	0.24
DCF Cost Effectiveness ($/ton)	6,442	1,904	3,599	5,910	8,865
LCF Cost Effectiveness ($/ton)	10,308	3,047	5,759	9,457	14,186

To achieve an 80% reduction, the cost effectiveness for container glass melting furnace ranges from $1,900/ton to $8,900/ton ($3,000/ton to $14,200/ton, using LCF). All of these scenarios using the aforementioned NOx reduction technologies for flue gas treatment of container glass melting furnaces are considered cost effective.

Review of ETS's Analysis for Container Glass Melting Furnaces

ETS, Inc. was commissioned by SCAQMD staff to provide an independent evaluation of the previously described BARCT and cost analysis. ETS conducted a site visit at the facility to verify site specific considerations for the installation of control equipment.

For the Vendor 1 estimates, the calculation of the installation costs were adjusted to reflect 40% of the equipment costs, instead of being scaled from the base equipment case. Additionally, a contingency of 15% of the capital costs was applied to the overall estimate.

The Vendor 2 estimates were also adjusted by ETS for several items. Foundation and ductwork costs were added, as well as costs for new stacks for both options (single and three SCRs). Operation and labor costs were added to the annual costs for both options as well as costs for power consumption with the addition of a booster fan. The annual catalyst replacement costs were also adjusted for both options to reflect labor costs to replace the catalyst, along with recycling/disposal costs for spent catalyst. Additionally, a contingency of 15% of the capital costs was applied to the overall estimate.

The Vendor 3 cost estimates were not evaluated by ETS because they felt that the cost estimates provided by the equipment vendors with actual field experience with NOx removal would provide better estimates than the EPA cost manual method. Also, there was a disparity in the costs with the vendor estimates versus the EPA cost manual method because economics of scale were not taken into consideration, such as volume cost savings for multiple pieces of equipment.

Since the glass melting furnaces at this facility are also SOx emission sources, the flue gas has to be at a sufficiently high temperature to prevent ammonium bisulfate formation (ABS) while also removing NOx emissions effectively. ABS forms when the SO_3 in the flue gas reacts with the ammonia in the SCR system to produce ammonium salts. If the flue gas temperature is above the dew point for ABS, it will remain in the gaseous phase. However, if the temperature of the flue gas falls below the dew point for ABS, it will precipitate and deposit as a sticky substance on the SCR catalyst matrix. The result is reduced activity of the SCR catalyst and it will need to be reheated to reverse the process and reactivate it. Upon speaking with the equipment vendors, the SOx emissions from the glass melting furnaces would not result in ABS formation as long as the flue gas temperature remains as high as possible, any heat loss from the ductwork is mitigated, and there is not an overly lengthy duct run constructed to the SCR. The current stack temperatures at the facility are adequately above the ABS dew point and, therefore, there is no foreseeable issue with ABS deposition on the SCR catalyst.

ETS concurs that the NOx emission levels that are achievable is 80% for this source category. Achieving this level would be feasible with both technologies evaluated (i.e., ceramic filtration system or SCR). The plot considerations at this facility are complex, leaving little room for the installation of control equipment. The Vendor 1 system would involve removing the existing SOx dry scrubbers to create additional space and would need to be tied in presumably under a facility shutdown period. The Vendor 2 system would be complex as well, but ETS concurs that there is sufficient plot space for the installation of SCR.

To achieve the proposed BARCT level, the revised cost effectiveness for container glass melting furnaces ranges from \$3,000/ton to \$8,900/ton (\$4,700/ton to \$14,200/ton, using LCF). All of these scenarios using the aforementioned NOx reduction technologies for flue gas treatment of container glass melting furnaces are considered feasible and cost effective.

Table N. 3 - ETS Revisions to Cost Effectiveness for Container Glass Melting Furnaces

Vendor 1: Dry scrubbing and ceramic filter system installed after the furnaces, replacing the dry scrubber and ESP. NOx, SOx, and PM removal.					
Vendor 2: SCR system installed post ESP. NOx removal only. Option 1: single chamber. Option 2: three chambers.					
Vendor 3: SCR system installed post ESP using costs provided by facility per EPA cost manual. NOx removal only. Option 1: two chambers. Option 2: three chambers.					
	Vendor 1	**Vendor 2 Option 1**	**Vendor 2 Option 2**	**Vendor 3 Option 1**	**Vendor 3 Option 2**
	Staff's Estimate (ETS's Estimate)	Staff's Estimate (ETS's Estimate)	Staff's Estimate (ETS's Estimate)	Staff's Estimate*	Staff's Estimate*
Capital Costs ($)	5,134,891 (5,684,463)	2,070,000 (2,685,250)	5,000,000 (5,405,000)	4,096,959	6,145,439
Annual Costs ($)	567,686*	132,500 (240,909)	180,750 (360,753)	560,123	840,185
Present Worth Value ($)	14,003,287 (14,522,859)	4,139,195 (6,448,737)	7,823,677 (11,040,686)	12,847,207	19,270,811
Emission reductions (tpd)	0.24	0.24	0.24	0.24	0.24
DCF Cost Effectiveness ($/ton)	6,442 (6,695)	1,904 (2,967)	3,599 (5,079)	5,910	8,865
LCF Cost Effectiveness ($/ton)	10,308 (10,713)	3,047 (4,747)	5,759 (8,127)	9,457	14,186

*No revisions were made by ETS to the Vendor 3 costing or the indicated fields

References for Container Glass Melting Furnaces

1. *Alternative Control Techniques Document – NOx Emissions from Glass Manufacturing.* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. June 1994; EPA-453/R-94-037.

2. Staff Report of Proposed Amendments to SOx RECLAIM. Agenda item 37 of the SCAQMD Governing Board Meeting. November 5, 2010.

3. *World's Largest Supplier of Ceramic Catalyst Filter Systems*. Tri-Mer Corporation Brochure, 2015; www.tri-mer.com.

4. *Ammonium Bisulphate Inhibition of SCR Catalysts*. Thogersen, J.; Slabiak, T.; White, N. Haldor Topsoe.

5. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

6. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

Appendix O– Sodium Silicate Furnace

Process Description

In the NOx RECLAIM program there is only one facility that produces sodium silicate. Sodium silicate is a substance either in a solid or liquid form that has a variety of industrial uses. It is manufactured by heating soda ash and sand in a melting furnace. The materials react with heat to produce sodium silicate and carbon dioxide.

In 2005, there was no new BARCT proposed for this source category. The emission factor has remained unchanged since 2000 (Tier 1), which is 6.4 pounds of NOx per ton of glass pulled. This unit is considered a glass melting furnace, but since it processes sodium silicate, it is different than other types of glass melting furnaces such as container glass, flat glass, etc.

Current Emission Inventory

The single source sodium silicate melting furnace is a NOx major source.

Table O. 1 - 2011 Emissions for Sodium Silicate Furnace

Equipment Type	Number of Units	2011 Emissions (tpd)
Sodium Silicate Furnace	1	0.11

Control Technology

The raw material batch feed is delivered into the melting furnace which is fired by several natural gas-fired burners that melt the process feed. The flue gas then exits the furnace via a stack into the atmosphere. Combustion technology can often be employed to achieve some NOx reductions. Blower air staging, for example, can lower the temperature and result in lowering NOx emissions by around 15 to 20%.

To effectively achieve the largest reduction, however, selective catalytic reduction (SCR) is the technology that is best suited for significant flue gas treatment of NOx. This technology uses a precious metal catalyst that selectively reduces NOx in the presence of ammonia. Ammonia is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of the catalyst to produce nitrogen and water vapor. The typical operating temperature of the exhaust gas is between 450 and 850 degrees F.

For glass melting applications, an alternate technology is available that has been achieved in practice, primarily for multi-pollutant control. The system utilizes Ultra Cat ceramic fiber filters. Please refer to Appendix M for further descriptions. This technology is guaranteed to achieve an 80% NOx reduction.

Proposed BARCT level and Emission Reductions

In command and control, SCAQMD Rule 1117 set limits for glass melting furnaces. Last amended in 1984, the rule limits NOx emissions to 4.0 pounds per ton of glass pulled, effective in 1992. The 2005 NOx RECLAIM amendment proposed no new BARCT for sodium silicate furnaces or other glass melting furnaces, so these units have been only required to meet the Year 2000 Tier 1 emission level. The Tier 1 emission level for sodium silicate furnaces is 6.4 pounds per ton of glass pulled.

The single unit in the NOx RECLAIM universe is currently compliant with the Tier 1 emission level. For sodium silicate furnaces based on vendor discussions, the proposed BARCT level for this source category is an 80% reduction and the control technology to achieve the NOx reductions is SCR or the Ultra Cat ceramic filter system.

The emission reductions achieved from the sodium silicate furnace, based on the reported value of emissions, amounts to 0.09 tons per day. This is the incremental reduction from the Tier 1 emission level and is almost equivalent to the Tier 1 emission level for container glass melting furnaces (1.2 lbs/ton of glass pulled).

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using vendor-supplied costs. There are no site-specific conditions that would increase the installation costs dramatically.

For SCR, the equipment and installation costs include the SCR chamber, one layer of catalyst with extra space for a second layer, supporting structure, ammonia skid, programmable logic control system (PLC), and engineering/fabrication. The foundation and ductwork was estimated to be 60% of the equipment and installation costs. The annual operating costs include ammonia consumption and catalyst replacement costs, which for this installation were conservatively assigned an annual replacement interval. In addition, a 20% contingency was added to the annual costs for freight and installation.

For the Ultra Cat ceramic filter system, the equipment costs include the emission control system, ammonia skid, booster fan, and engineering services. The installation costs were calculated to be 40% of the equipment costs. The annual operating costs include ammonia consumption, power consumption, labor, waste disposal and replacement filter costs. Since this facility is not a SOx source, dry sorbent injection for SOx removal would not be required.

For both technologies, a present worth value (PWV) was calculated for the sodium silicate furnace using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

$$PWV = TIC + (15.622 \times AC)$$

A cost effectiveness value was then calculated for each technology using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This method of calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

$$\text{Cost Effectiveness} = PWV / (ER \times 365 \times 25 \text{ years})$$

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

$$\text{LCF Cost Effectiveness} = (TIC \times CRF) + AC / (ER \times 365),$$

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

Table O. 2 - Cost Effectiveness for Sodium Silicate Furnace

Control Technology	TIC ($)	AC ($)	PWV ($)	ER (tpd)	DCF C.E. ($/ton)
SCR	1,600,000	76,315	2,792,193	0.09	3,470
Ultra Cat	1,986,161	166,016	4,579,663	0.09	5,691

The cost effectiveness for the sodium silicate furnace ranges from $3,500/ton to $5,700/ton ($5,600/ton to $9,100/ton, using LCF). This is to achieve an 80% NOx reduction. Both technologies for reducing NOx for the sodium silicate furnace are considered cost effective.

Review of ETS's Analysis for Sodium Silicate Furnace

ETS, Inc. was commissioned by SCAQMD staff to provide an independent evaluation of the previously described BARCT and cost analysis. ETS conducted an evaluation of the control technology and the costs for the installation of the control equipment.

For both vendor estimates, a contingency of 15% was applied the total direct and indirect capital costs. For the Vendor 2 estimate, the capital costs pertinent to SO_2 treatment were removed since this system would be removing NOx only.

To achieve the proposed BARCT level, the revised cost effectiveness for the sodium silicate furnace ranges from $3,800/ton to $5,700/ton ($6,000/ton to $9,200/ton, using LCF). Both scenarios using the aforementioned NOx reduction technologies for flue gas treatment of the sodium silicate furnace are considered feasible and cost effective.

Table O. 3 - ETS Revisions to Cost Effectiveness for Sodium Silicate Furnace

Vendor 1: Dry scrubbing and ceramic filter system installed after the furnaces, replacing the dry scrubber and ESP. NOx, SOx, and PM removal.		
Vendor 2: SCR system installed post ESP. NOx removal only. Option 1: single chamber. Option 2: three chambers.		
	Vendor 1	**Vendor 2**
	Staff's Estimate (ETS's Estimate)	Staff's Estimate (ETS's Estimate)
Capital Costs ($)	1,600,000 (1,840,000)	1,986,161 (2,009,243)
Annual Costs ($)*	76,315	166,016
Present Worth Value ($)	2,792,193 (3,032,193)	4,579,663 (4,602,745)
Emission reductions (tpd)	0.09	0.09
DCF Cost Effectiveness ($/ton)	3,470 (3,768)	5,691 (5,719)
LCF Cost Effectiveness ($/ton)	5,552 (6,029)	9,106 (9,152)

*No revisions were made by ETS

References for Sodium Silicate Furnace

1. *World's Largest Supplier of Ceramic Catalyst Filter Systems*. Tri-Mer Corporation Brochure, 2015; www.tri-mer.com.

2. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

3. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

Appendix P – Metal Heat Treating Furnaces >150 MMBTU/hr

Process Description

In the NOx RECLAIM program there is one facility that operates these furnaces among the top 37 facilities. For the 2005 NOx RECLAIM amendment, a BARCT level of 45 ppm (0.055 lb/MMBTU) was established for metal heat treating furnaces.

Current Emission Inventory

Among the top 37 facilities in the NOx RECLAIM program, there are two furnaces above 150 MMBTU/hr that are metal heat treating furnaces for processing steel.

Table P. 1 - 2011 Emissions for Metal Heat Treating Furnaces >150 MMBTU/hr

Equipment Type (at Top 37 Facilities)	Number of Units	2011 Emissions (tpd)
Furnace >150 MMBTU/hr	2	0.49

Control Technology

As with all combustion sources, the type of burner used can affect the emissions. Some burners are lower NOx emitting than others. But for these types of furnaces, there are often dozens of burners that cumulatively require a high heat input. To achieve higher efficiency and to consume less fuel, recuperative and regenerative burners are used. These burners employ the principle of using preheated inlet air which is heated by the exhaust gases for more efficient combustion.

To effectively achieve a significant NOx reduction, however, selective catalytic reduction (SCR) is the technology that is best suited for the flue gas treatment of NOx. This technology uses a precious metal catalyst that selectively reduces NOx in the presence of ammonia. Ammonia is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of the catalyst to produce nitrogen and water vapor. The typical operating temperature of the exhaust gas is between 450 and 850 degrees F.

Proposed BARCT level and Emission Reductions

In command and control, SCAQMD Rule 1147 set limits for metal heat treating furnaces at 60 ppm at 3% O_2 (0.073 lb/MMBTU). This rule was adopted in 2008 to address NOx emissions from miscellaneous sources. The 2005 NOx RECLAIM amendment proposed a BARCT level of 45 ppm at 3% O_2 (0.055 lb/MMBTU).

Based on vendor discussions for furnaces above 150 MMBTU/hr, the proposed BARCT level for this source category is an 80% reduction and the control technology to achieve the NOx reductions is SCR. An 80% NOx reduction from the 2005 BARCT level is equivalent to 9 ppm at 3% O_2.

The 2011 emissions adjusted to the 2005 BARCT level amount to 0.70 tons per day. The incremental reductions from each furnace from the 2005 BARCT level to the proposed BARCT level are 0.28 tons per day. One of the furnaces is already operating with an SCR system and is currently achieving around 20 ppm NOx. The source category incremental emission reductions achieved from the metal heat treating furnaces above 150 MMBTU/hr from the 2005 BARCT level amount to 0.56 tons per day.

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using vendor-supplied costs and the costs from an existing installation.

For SCR, the vendor-based equipment and installation costs include the SCR catalyst, reactor and ductwork, ammonia skid, dilution air fan, civil work, and installation. A contingency value of 200% of the SCR equipment costs was used to estimate the installation, foundation, civil work, and other construction uncertainties. The annual operating costs include ammonia consumption, catalyst replacement costs (2 year replacement interval), power consumption, and maintenance.

The existing equipment-based equipment costs include installation, SCR catalyst system, ammonia skid, and control system. A 60% contingency value of the equipment and installation cost was used to estimate the costs for other ductwork. The annual operating costs include ammonia consumption, catalyst replacement costs (2 year replacement interval), and maintenance.

For both scenario cases, a present worth value (PWV) was calculated for the metal heat treating furnaces using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

$$PWV = TIC + (15.622 \times AC)$$

A cost effectiveness value was then calculated for each case scenario using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This method of calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

Cost Effectiveness = PWV / (ER x 365 x 25 years)

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

LCF Cost Effectiveness = (TIC x CRF) + AC / (ER x 365),

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

Table P. 2 - Cost Effectiveness for Furnaces > 150 MMBTU/hr

Control Technology	TIC ($)	AC ($)	PWV ($)	ER (tpd)	DCF C.E. ($/ton)
Vendor-based	2,800,152	440,631	9,683,684	0.28	3,800
Existing equipment-based	3,732,800	255,600	7,725,783	0.28	3,000

The cost effectiveness for furnaces above 150 MMBTU/hr ranges from $3,000/ton to $3,800/ton ($4,800/ton to $6,100/ton, using LCF). Achieving an 80% NOx reduction, SCR technology applied for reducing NOx for these furnaces is considered cost effective.

Review of ETS's Analysis for Metal Heat Treating Furnaces >150 MMBTU/hr

ETS, Inc. was commissioned by SCAQMD staff to provide an independent evaluation of the previously described BARCT and cost analysis. Based on staff's analysis and the review of technical information, ETS concurs that the NOx reduction level that can be achieved with SCR technology is 80%. No changes to the cost estimates were made.

References for Metal Heat Treating Furnaces >150 MMBTU/hr

1. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

2. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

Appendix Q – Non-Refinery, Non-Electrical Generating Facility Stationary Gas Turbines

Process Description

In the RECLAIM program, stationary gas turbines are used primarily to drive compressors or to generate power. In command and control, Rule 1134 limits the NOx emissions for all gaseous and liquid-fueled engines that are above 0.3 MW. Gas turbines operate either in simple cycle or combined cycle. Simple cycle units use the mechanical energy of shaft work that is transferred to and used by a gas compressor, for example, or to run an electrical generator to produce electricity. A combined cycle unit adds an additional element of heat recovery from its exhaust gases to produce more power by way of a steam generator. Combined cycle units are more efficient due to their use of two work cycles from the same shaft operation. Gas turbines can operate on both gaseous and liquid fuels. Gaseous fuels include natural gas, process gas, and refinery gas. Liquid fuels typically include diesel. The units in this category are not electrical generating facility turbines (turbines that produce solely electric utility power). Some of these units are cogenerating units that, in addition to producing in-house power, also recover the useful energy from heat recovery for producing process steam. In 2005, there was no new BARCT proposed for this source category. The emission factor has remained unchanged since 2000 (Tier 1), which equates to 0.06 lb/MMBTU.

Current Emission Inventory

Among the top thirty seven non-electrical generating facility NOx emitting facilities in the RECLAIM universe, there are twenty gas turbines that are either major or large source units. Four of these units are currently utilizing some level of NOx control with selective catalytic reduction (SCR). The OCS turbines, which are fired on diesel or process gas, have the highest NOx emission concentrations in this source category. Six of these units are operated on an offshore oil drilling platform (outer continental shelf, or OCS).

Table Q. 1 - 2011 Emissions for RECLAIM Non-Electrical Generating Facility Gas Turbines

Turbine Type	Number of Units	2011 Emissions (tpd)
Total	20	1.92
Gas Compression	7	0.59
Cogeneration	6	0.75
Power Generation	1	0.09
OCS	6	0.49

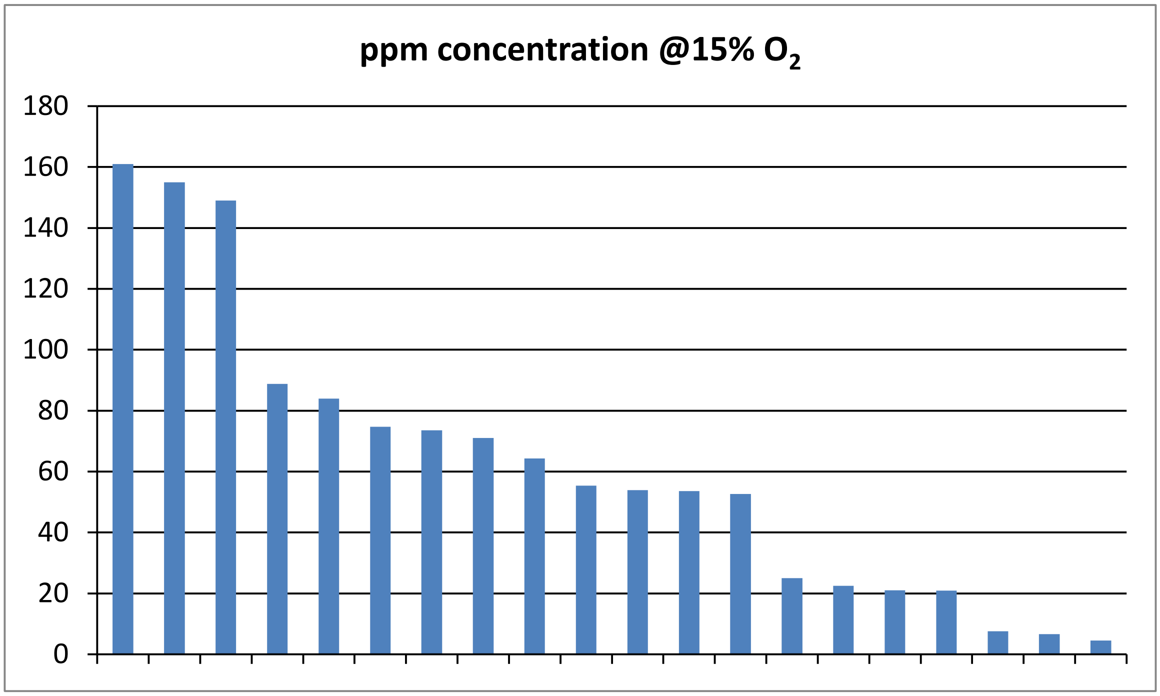


Figure Q. 1 - NOx Concentrations for Non-Electrical Generating Facility Gas Turbines at Top 37 Emitting Facilities

Control Technology

An uncontrolled unit will typically be emitting well over 100 ppm of NOx. There are several methods of NOx control for gas turbines, with differing levels of reduction.

Steam or water injection involves the introduction of either medium into the combustor flame zone to lower the flame temperature, thus reducing NOx formation. Typically, this will reduce NOx emissions up to 60%. Dry low emissions (DLE or DLN) is a type of dry control which involves a major modification to the turbine's combustion system. Unlike diffusion flames where the fuel and air mixes and combusts at the same time, DLE combustors are premixed, where the air and fuel mix first and then are combusted to produce a lower flame temperature. In addition, these systems operate under lean conditions, often with dual staged-combustion, further lowering NOx emissions. DLE technology can achieve NOx levels between around 10 and 45 ppm.

Selective catalytic reduction (SCR) is the most effective technology that can achieve ultra low NOx emissions. The technology uses a precious metal catalyst that selectively reduces NOx in the presence of ammonia. Ammonia is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of the catalyst to produce nitrogen and water vapor. The typical operating temperature of the exhaust gas is between 450 and 850 degrees F.

Proposed BARCT level and Emission Reductions

In command and control, SCAQMD Rule 1134 set limits for gas turbines for a range of sizes (ratings), with the limits varying between 9 and 25 ppm, corrected to 15% oxygen content. The 2005 NOx RECLAIM amendment proposed no new BARCT for gas turbines, so these units have been only required to meet the Year 2000 Tier 1 emission level. The Tier 1 emission level for natural gas and diesel fueled gas turbines in equivalent to 0.06 lb/MMBTU, which corresponds to approximately 17 ppm at 15% O_2. This reference limit can be higher, depending on the efficiency of the unit. The majority of the RECLAIM units in this source category have not installed the controls to meet the Tier 1 emission level.

For the non-electrical generating facility, non-refinery gas turbines in the top 37 facilities and based on vendor discussions and achieved in practice BACT installations, the proposed BARCT level for this source category is 2 ppm @15% $O_{2,}$ and the control technology to achieve the NOx reductions is SCR. For units that are emitting less than 40 ppm NOx at 15% O2, a 2 ppm emission level is achievable with SCR only. In Figure Q.1, this would apply to the 7 units to the right of the chart. However, for those units emitting at 40 ppm, a 95 percent reduction is achievable. For the remainder of these units, a 95% reduction would achieve around 3 to 4 ppm. The power generating offshore units would achieve 8 ppm at a 95% reduction for their current emission level since they have the highest emissions. The offshore gas compression turbines can achieve 5 ppm at a 95% reduction. A 2 ppm level would be achievable for the units emitting above 40 ppm if these units would install either wet or dry combustion controls to comply with the Tier 1 emission level. The single power generating gas turbine that is non-OCS currently operates with an SCR system permitted at 5 ppm for NOx. Staff believes that a replacement of the catalyst system would be sufficient to meet the 2 ppm BARCT level. As a worst case, a present worth value was calculated from the same curve derived from existing refinery power generating units for a complete replacement of the SCR catalyst and equipment.

The emission reductions achieved from both subsets of units emitting above and below 40 ppm in the non-OCS sector are 1.04 tons per day. This is the incremental reduction from the Tier 1 level. The OCS units would add an additional 0.07 tons per day.

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using vendor-supplied costs. The vendor-supplied costs were for the SCR equipment only. This consists of the SCR housing, SCR catalyst, mixing ductwork, ammonia injection skid, PLC system, and CFD flow modeling.

Installation costs can vary due to the type of facility and any site-specific limitations. To derive a reasonable estimate, the installation costs were calculated to be double (or 200%) of the equipment costs. Since an SCR installation at an offshore facility could be more complicated than a typical onshore installation, the installation costs were calculated at four times the equipment costs to account for the unique site considerations for this type of installation. The annual operating costs include catalyst replacement (replacement interval of three years), ammonia consumption (19%), and electrical consumption.

A present worth value (PWV) was then calculated for each gas turbine using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

$$\text{PWV} = \text{TIC} + (15.622 \times \text{AC})$$

A cost effectiveness value was then calculated for each gas turbine using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This method of calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

$$\text{Cost Effectiveness} = \text{PWV} / (\text{ER} \times 365 \times 25 \text{ years})$$

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

$$\text{LCF Cost Effectiveness} = (\text{TIC} \times \text{CRF}) + \text{AC} / (\text{ER} \times 365),$$

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

The cost effectiveness for non-electrical generating facility, non-OCS gas turbines ranges from $4,700/ton to $35,900/ton ($7,500/ton to $57,500/ton, using LCF). This is to achieve a 95% reduction for those units emitting higher than 40 ppm and to achieve 2 ppm for those emitting lower than 40 ppm. For these gas turbines, the installation of SCR to treat NOx is cost effective. If the units emitting above 40 ppm install either wet or dry combustion controls to meet the Tier 1 emission level, then meeting 2 ppm is achievable.

The cost effectiveness for the offshore gas turbines ranges from $51,400/ton to $59,200/ton ($82,300/ton to $94,700/ton, using LCF). These figures reflect the power generating units achieving 8 ppm and the gas compression units meeting 5 ppm with SCR only. Since the cost effectiveness is above $50,000/ton and based on past rule makings, the OCS gas turbines are not considered cost effective in achieving the incremental NOx BARCT reductions from the Tier 1 level.

Table Q. 2 - Cost Effectiveness for Non-Electrical Generating Facility Gas Turbines

Unit	TIC ($)	AC ($)	PWV ($)	ER (tpd)	DCF C.E. ($/ton)
1	2,786,139	707,847	13,844,125	0.081	18,716
2	2,858,592	687,666	13,601,308	0.085	17,537
3	2,780,064	727,308	14,142,076	0.084	18,518
4	2,583,085	297,613	7,232,403	0.015	52,748
5	2,604,485	352,643	8,113,472	0.015	59,174
6	2,608,400	329,730	7,759,450	0.015	56,592
7	2,252,960	68,133	3,317,340	0.007	51,422
8	2,259,305	75,832	3,443,960	0.007	53,384
9	2,269,455	68,955	3,346,666	0.007	51,876
10	1,517,898	68,321	2,585,211	0.009	33,250
11	1,519,272	65,261	2,538,781	0.008	35,916
12	1,531,680	69,149	2,611,931	0.009	33,594
13	1,516,755	63,256	2,509,164	0.008	35,497
14	2,320,584	437,781	9,159,602	0.156	6,478
15	1,443,846	80,740	2,705,163	0.025	11,658
16	1,442,694	92,373	2,885,744	0.016	19,823
17	2,765,694	555,222	11,439,367	0.269	4,666
18	2,438,727	389,347	8,521,114	0.128	7,310
19	2,432,730	397,575	8,643,648	0.135	7,019
20	*	*	13,597,600	0.060	24,979

*PWV was determined from cost curve for refinery gas turbines (Figure C-5)

Review of ETS's Analysis for Metal Heat Treating Furnaces above 150 MMBTU/hr

ETS, Inc. was commissioned by SCAQMD staff to provide an independent evaluation of the previously described BARCT and cost analysis. ETS concurs with the costing information and the conservative approach taken for calculating the costs for the possibly varied installations, given the site-specific aspects. ETS also concurs with the achievability of the reductions using SCR technology and no changes to the cost estimates were made.

References for Non-Refinery, Non-Electrical Generating Facility Stationary Gas Turbines

1. *Best Available Retrofit Control Technology Assessment – TXI Riverside Cement.* SCAQMD, August 8, 2008.

2. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

3. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

4. *Combustion and Fuels*. Solar Turbines Incorporated Presentation, Luke Cowell, June 6, 2012.

5. *Catalog of CHP Technologies: Combustion Turbines*. United States Environmental Protection Agency - Combined Heat and Power Partnership, March 2015.

6. *Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines.* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. January 1993; EPA-453/R-93-007.

7. *AP-42, Fifth Edition: Compilation of Air Pollutant Emission Factors*. United States Environmental Protection Agency, January 1995.

Appendix R – Non-Refinery Stationary Internal Combustion Engines

Process Description

Stationary Internal Combustion Engines (ICEs) are used primarily to drive pumps, compressors, or to generate power. In command and control, Rule 1110.2 limits the NOx emissions for all gaseous and liquid-fueled engines that are above 50 brake horsepower (bhp). There are generally two types of engines, spark-ignited (SI) or compression ignited (CI) engines. SI engines ignite the air/fuel mixture with a spark while CI engines use the heat of compression to ignite the fuel that is injected into the combustion chamber.

Engines can run at either stoichiometrically rich or lean conditions, depending on the air to fuel ratio. Rich combustion corresponds to an air /fuel ratio that is fuel-rich while lean combustion corresponds to a fuel-lean air/fuel ratio. Small SI engines typically run as rich burn, but many larger units as well as CI engines operate under lean conditions. Usually, more air is inducted than is required for complete combustion and the resultant exhaust oxygen level is high (over 5%). Rich burn engines typically operate very close to stoichiometric conditions by drawing only the necessary air to combust the fuel. Spark-ignited engines are typically fired on gaseous fuels such as natural gas, while compression-ignited engines are fired on liquid fuels such as diesel.

In 2005, there was no new BARCT proposed for this source category. Consequently, the emission factor has remained unchanged since 2000 (Tier 1), which equates to about 57 ppm at 15% O_2 for natural gas-fired engines. During the 2008 amendment of Rule 1110.2, most stationary ICEs outside of RECLAIM (with the exception of biogas engines) were required to meet a NOx emission limit of 11 ppm at 15% O_2 by July 1, 2011.

Current Emission Inventory

Among the top thirty seven NOx emitting facilities in the RECLAIM universe, there are thirty one engines that are either major or large source units. Nine of these units are controlled with NSCR (non-selective catalytic reduction) as these engines are rich burn. Sixteen of these engines are SI lean burn units, while the remaining six are CI lean burn units. The CI lean burn units are all operated on an offshore oil drilling platform (outer continental shelf, or OCS). Six of the SI lean burn units are two-stroke engines (See Table 1). The engine sizes range from a little over 700 bhp to 5,500 bhp.

Table R. 1 - 2011 Emissions for Internal Combustion Engines at Top 37 Facilities

Engine Type (at Top 37 Facilities)	Number of engines	2011 emissions (tpd)
Lean Burn (Spark-Ignited)	16	0.34
Lean Burn (Compression Ignited), OCS	6	0.03
Rich Burn (Spark-Ignited)	9	0.02
Electrical Generating Facility (2 stroke)	6	0.18
Total	37	0.56

There are also 6 additional ICEs that belong to a power producing facility, and the combined emissions from these engines were 0.18 tons per day in 2011. These engines are 2-stroke engines that are fired on diesel fuel due to the lack of access to natural gas.

CI engines, which are fired on diesel, have the highest NOx emission concentrations in this source category. 2-stroke SI engines have higher NOx emissions than 4-stroke SI engines since the higher efficiencies in 2-stroke engines translate to a hotter combustion temperature that can create more NOx.

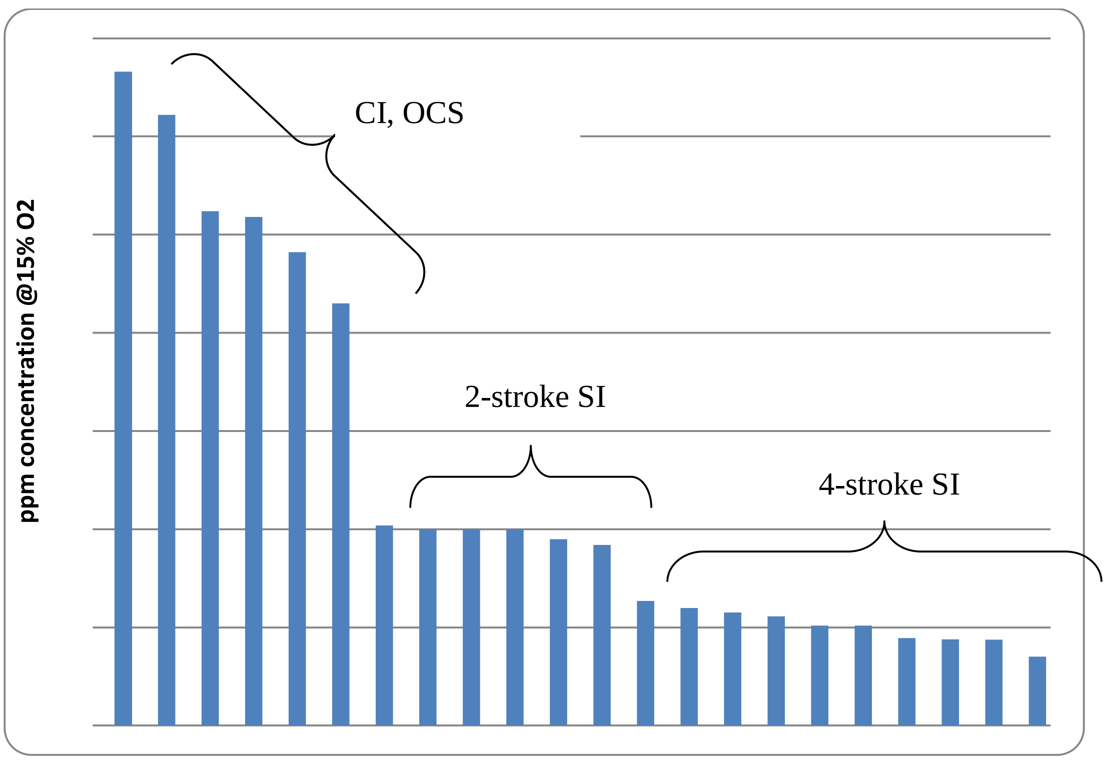


Figure R. 1 - NOx concentrations for Lean Burn ICEs at Top 37 Emitting Facilities

Control Technology

The flue gas from rich burn engines is typically very low in excess oxygen. This enables NOx reduction to take place via Non-Selective Catalytic Reduction technology (NSCR), which is inexpensive, readily installed, and simultaneously removes NOx, CO, and VOC. NSCR (or three-way) catalysts have been commercially available for many years and can achieve NOx removal efficiencies of over 90 percent. The catalyst reduces NOx to nitrogen and oxygen in the presence of CO and VOC, while simultaneously oxidizing CO and VOC to form carbon dioxide and water. Precise air/fuel ratio control is required since the catalytic reactions must occur within a narrow air/fuel ratio band.

With lean burn exhaust the higher oxygen content does not allow effective removal of NOx with NSCR. On this basis, CO and VOC will have a preferential reaction with the oxygen instead of the NOx. In this case, Selective Catalytic Reduction (SCR) is the technology of choice. Oxygen is an essential ingredient in the SCR reactions and the excess oxygen in the exhaust gas provides this. Ammonia (or urea) is injected in the flue gas stream where it reacts with NOx and oxygen in the presence of a catalyst to produce nitrogen and water vapor. The catalyst material is typically a base metal catalyst such as titanium dioxide or vanadium pentoxide, and operates within a temperature range of 450 to 850 F.

Proposed BARCT level and Emission Reductions

The 2008 amendment to Rule 1110.2 established a NOx emission level of 11 ppm @15% O_2 for most IC engines. The technology identified for rich burn engines was NSCR while the technology identified for lean burn engines was SCR. The effective date for complying with the final rule limit has been in effect for over four years. NSCR is feasible for rich burn engines and SCR is feasible for both two-stroke and four-stroke lean-burn engines.

The 2005 RECLAIM amendment proposed no new BARCT for IC engines, so these units have been only required to meet the Year 2000 Tier 1 emission level. For the non-electrical generating facility engines in the top 37 emitting facilities, the proposed BARCT level is 11 ppm @15% O_2. The rich burn engines in this category have all been retrofitted with NSCR and most of them meet the proposed BARCT level. These three way catalysts were installed to control CO and VOC for compliance with Rule 1110.2 requirements by July 1, 2011, since these pollutants are not governed under RECLAIM rules. There is an added benefit with three way catalysts because they also control NOx and this has resulted in emission reductions for these engines. For lean burn engines, however, the control technology to achieve the NOx reductions is SCR. If all the non-OCS engines in this category were to achieve the proposed BARCT level, the emission reductions from the Tier 1 level would be 0.84 tons per day. There is a portion of this reduction that is attributed to the rich burn engines and it amounts to 0.07 ton per day. Recent source tests indicate that the majority of these engines are already meeting the proposed BARCT level of 11 ppm. It is assumed that these engines will continue to meet the 11 ppm emission level.

The electrical generating facility engines, since they are 2-stroke diesel engines, are more difficult in terms of reducing NOx emissions. These engines are isolated and there is no other fuel backup. The unique nature of these engines provides a challenge with regards to very low allowable backpressures, which makes SCR an inflexible treatment option. Therefore, there is no new proposed BARCT for electrical generating facility ICEs.

The OCS engines in this category will not be subject to the new BARCT because the engines at offshore platforms run rig generators that are often variable in load. SCR systems need a more constant load so that the proper operating temperatures can be sustained for effective NOx removal.

Cost Effectiveness

The total installed costs (TIC), which include equipment and installation costs were calculated by using both vendor-supplied costs along with installation costs from an existing SCR installation on a lean-burn engine. The vendor-supplied costs were for the SCR equipment only. This consists of the SCR housing, SCR catalyst, mixing ductwork, expansion joint, urea injection skid (control system, pump, dosing unit), and an air compression/drying system.

Installation costs can vary due to the type of facility and any site-specific limitations. To derive a reasonable estimate, the costs from an achieved in practice SCR installation on a lean-burning engine were used. This engine is located at Orange County Sanitation District (OCSD), is fired on natural gas and digester gas, and is retrofitted with an oxidation catalyst and SCR. It was installed in 2009 and has been consistently been meeting the 11 ppm NOx limit of Rule 1110.2. The catalyst system had to be placed on an externally constructed platform because of the site constraints inside the engine building. These additional costs have been included as part of this analysis in anticipation of any supplemental support structures necessary to accommodate the SCR system. The 2009 dollar figures for the OCSD installation were raised to 2013 dollar values using the Marshall & Swift Index inflation factor. The installation costs for all the affected engines were scaled by horsepower based on the costs for this installation at OCSD.

The annual operating costs include catalyst replacement, reagent consumption, reagent delivery system maintenance, and electrical consumption. The annual costs for the OCSD installation assume a 3 year SCR catalyst replacement interval and were scaled for the engines in this source category by engine horsepower. For two-stroke engines, a very conservative replacement interval of one year was selected due to the potentially more contaminated exhaust gas stream (ash, soot) from this type of engine.

A present worth value (PWV) was then calculated for each engine using the TIC and annual costs (AC), and assumes a 4% interest rate and a 25-year equipment life per the equation below.

$$PWV = TIC + (15.622 \times AC)$$

A cost effectiveness value was then calculated for each engine using the present worth value and dividing by the incremental emission reductions (ER, in tons per day) from the Tier 1 level over the control equipment life (25 years). This method of calculating cost effectiveness utilizes the Discounted Cash Flow method (DCF).

$$\text{Cost Effectiveness} = PWV / (ER \times 365 \times 25 \text{ years})$$

Conversion to a Levelized Cash Flow (LCF) requires a calculation using the following equation:

$$\text{LCF Cost Effectiveness} = (TIC \times CRF) + AC / (ER \times 365),$$

where CRF is the Capital Recovery Factor assuming a 4% interest rate over an equipment life of 25 years.

Table R. 2 - Cost Effectiveness for Lean-Burn, Non-OCS ICEs

Unit	TIC ($)	AC ($)	PWV ($)	ER (tpd)	DCF C.E. ($/ton)
1	890,182	36,625	1,462,338	0.036	4,500
2	890,182	36,625	1,462,338	0.033	4,900
3	890,182	36,625	1,462,338	0.033	4,800
4	890,182	36,625	1,462,338	0.034	4,700
5	890,182	36,625	1,462,338	0.035	4,600
6	1,386,291	82,640	2,677,289	0.043	6,900
7	485,628	25,696	887,048	0.019	5,000
8	485,628	25,696	887,048	0.019	5,000
9	1,307,772	77,475	2,518,084	0.038	7,300
10	485,628	25,696	887,048	0.019	5,100
11	1,307,772	77,475	2,518,084	0.037	7,500
12	2,319,249	100,719	3,892,680	0.084	5,000
13	2,319,249	100,719	3,892,680	0.084	5,000
14	2,319,249	100,719	3,892,680	0.085	5,000
15	2,319,249	100,719	3,892,680	0.083	5,200
16	2,319,249	100,719	3,892,680	0.084	5,000

The cost effectiveness for non-electrical generating facility IC engines ranges from $4,500/ton to $7,500/ton ($7,200/ton to $12,000/ton, using LCF). For these engines, the installation of SCR to treat NOx is cost effective.

Review of ETS's Analysis for Non-Refinery Stationary Internal Combustion Engines

ETS, Inc. was commissioned by SCAQMD staff to provide an independent evaluation of the previously described BARCT and cost analysis. ETS concurs with the costing information and the conservative approach taken for calculating the costs for the possibly varied installations, given the site-specific aspects. ETS also concurs with the achievability of the reductions using SCR technology and no changes to the cost estimates were made.

References for Non-Refinery Stationary Internal Combustion Engines

1. *EPA Air Pollution Control Cost Manual*. United States Environmental Protection Agency. Office of Air Quality Planning and Standards. 2002; EPA/452/B-02-001.

2. *NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-Refinery Sector*. SCAQMD Contract #15343. ETS, Inc.; 2014.

3. *AP-42, Fifth Edition: Compilation of Air Pollutant Emission Factors*. United States Environmental Protection Agency, January 1995.

4. *Alternative Control Techniques Document – NOx Emissions from Stationary Reciprocating Internal Combustion Engines.* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. January 1993; EPA-453/R-93-032.

5. *Retrofit Digester Gas Engine with Fuel Gas Clean-up and Exhaust Emission Control Technology*. SCAQMD Contract #10114, Orange County Sanitation District, July 2011.

Appendix S – Non-Refinery Boilers >40 MMBTU/hr

In the top 37 emitting facilities, there are four boilers that are above 40 MMBTU/hr. They range between 49 and 247.3 MMBTU/hr. The 2005 BARCT level for these units was 9 ppm at 3% O_2. The incremental NOx reduction going from 9 ppm to a proposed BARCT level of 2 ppm would be 0.01 tons per day.

SCR would be the technology of choice for achieving NOx reductions for larger boilers. The costs for retrofitting these units were estimated from the ETS-adjusted vendor quotes for a similar sized installation for the sodium silicate furnace. The present worth value for the installation in on a 56.6 MMBTU/hr combustion furnace is $4,602,745. The present worth value for the largest unit was calculated from the cost curve developed for refinery boilers and heaters (Figure B-3).

The DCF cost effectiveness for all of the four units were calculated to be above $150,000 per ton of NOx. Therefore, retrofitting with SCR would not be cost effective. ETS concurs that the costs for installing SCR would not be cost effective for this source category.

Table S. 1 - Cost Effectiveness for Non-Refinery Boilers >40 MMBTU/hr

Unit	Rating (MMBTU/hr)	PWV ($)	Incremental Emission Reductions (tpd)	DCF Cost Effectiveness ($/ton)
1	57	4,602,745	0.003	182,107
2	62.5	4,602,745	0.003	153,938
3	49	4,602,745	0.0001	6,447,425
4	247.3	13,527,310	0.004	380,515

Appendix T – Survey Questionnaires for Non-Refinery Sector

South Coast Air Quality Management
2013 NOx RECLAIM
Survey Questionnaire for Non-Refineries
(Due Date: July 12, 2013)

Facility Contact

1. Please provide the facility contact for this project:
   Name: ________________________________
   Title: ________________________________
   Phone Number: _________________________
   Email Address: _________________________

Top NOx Emitting Equipment or Processes
(* The attached list may contain the information requested)

2. * Please verify the attached list for the top 10 NOx emitting equipment and processes at your facility in Compliance Year 2011 and their emissions.

3. Please mark on the attached list the NOx control equipment installed **after the 2005 NOx RECLAIM amendment**

Boilers, Heaters, Furnaces, Kilns, Turbines, and Cogeneration Units (Major and Large Sources)

4. For each major and large combustion source at your facility, please verify the following information in the attached list, and provide information if the attached list does not contain this specific information:
   k. * Device description, Device ID, Process Name
   l. * Emissions in CY 2011 (tons per day)
   m. * Maximum unit rating (MMBTU/hr)
   n. * Type of fuel used
   o. Fuel usage rate and BTU content of fuel
   p. Flue gas flow rate (million dry standard cubic feet), temperature, oxygen and water content
   q. Representative flue gas analysis and fuel gas analysis
   r. NOx concentration in the exhaust flue gas (ppmv at 3% O_2 or ppmv at 15% O_2). Please attach a copy of the most current source test reports/results.
   s. Allowable back pressure
   t. * Control technology used (e.g. LNB, SCR, NOx scrubber)

5. For the control technology identified in item #4 above:

h. Device description, Device ID
i. Manufacturer's name and performance. Please attach a copy of manufacturer's specification/guarantee
j. Design parameters (e.g. maximum flue gas flow rate, inlet and outlet ppmv, ammonia slip)
k. If the control device is shared between multiple NOx emitting sources, please identify all other sources that are vented to this control device
l. Dimension of the add-on NOx control device (e.g. length, width, height of the SCR, catalyst volume)
m. Cost information (capital costs, installation costs, and annual operating costs)
n. Installation date (e.g. July 2005)

6. Provide drawings that show location and distances between the major and large NOx sources at the facility.

Reports Submitted Under the U.S. EPA Consent Decree

7. If the facility must install control technology to reduce the NOx emissions under an U.S. Environmental Protection Agency (EPA)'s consent decree, please provide the District a copy of the most recent reports/test results submitted to the EPA related to this consent decree.

Feasible Control Approach Including Energy Efficiency Project

8. List any feasible control approach that your facility plans to install, including replacement of the existing units with higher energy efficient units, to further reduce your facility's NOx emissions and green-house gases. Provide a brief description of the control approach, manufacturer's name, estimated emission reductions, and cost information.

If you have any questions, please contact either:
Kevin Orellana (909) 396-3492, korellana@aqmd.gov, or
Gary Quinn, P.E. (909) 396-3121, gquinn@aqmd.gov

Please submit information via e-mail by July 12, 2013
to Kevin Orellana and Gary Quinn.
Thank you for participating in the Survey.

Part III – RTC Reduction Approaches

Part III contains information pertinent to the RTC reductions estimation. Part III contains three appendices: Appendix U contains a discussion on staff's approaches and calculation to determine the RTC reductions based on the 2015 BARCT levels assessed in Part I for the refinery sector and Part II for the non-refinery sector. Staff's calculation were also based on the 2011 audited NOx emissions for all NOx RECLAIM facilities except electrical generating facilities. For electrical generating facilities, staff used the 2012 baseline emissions. Appendix V contains the 2011 audited emissions, and Appendix W contains the 2012 baseline emissions for electrical generating facilities.

Appendix U – Staff's Proposal and CEQA Alternatives

Staff has considered several options to determine the most appropriate RTC shave distribution to effect emission reductions that will protect the environment, satisfy the state and federal CAA requirements, and satisfy AQMP commitments, while concurrently providing for growth and safeguards for the continued functioning of the RECLAIM program. The RTC reductions with the application of BARCT total 14.79 tons per day. However, an adjustment is proposed to the total RTC reductions to account for issues that have been raised by stakeholders regarding the BARCT analysis. These issues primarily focused on the potential uncertainties of the control costs for refinery boilers and heaters and the reliability and consistency in maintaining controlled NOx concentrations for the coke calcining unit. With these adjustments, the RTC reduction that would be applied for the shave approaches would total 14 tons per day by 2023.

The shave proposals under consideration affect four major groups within the NOx RECLAIM universe:

- Major Refineries and Investors
- Top 90% of RTC Holders
- Others (Bottom 10 percent of RTC Holders)

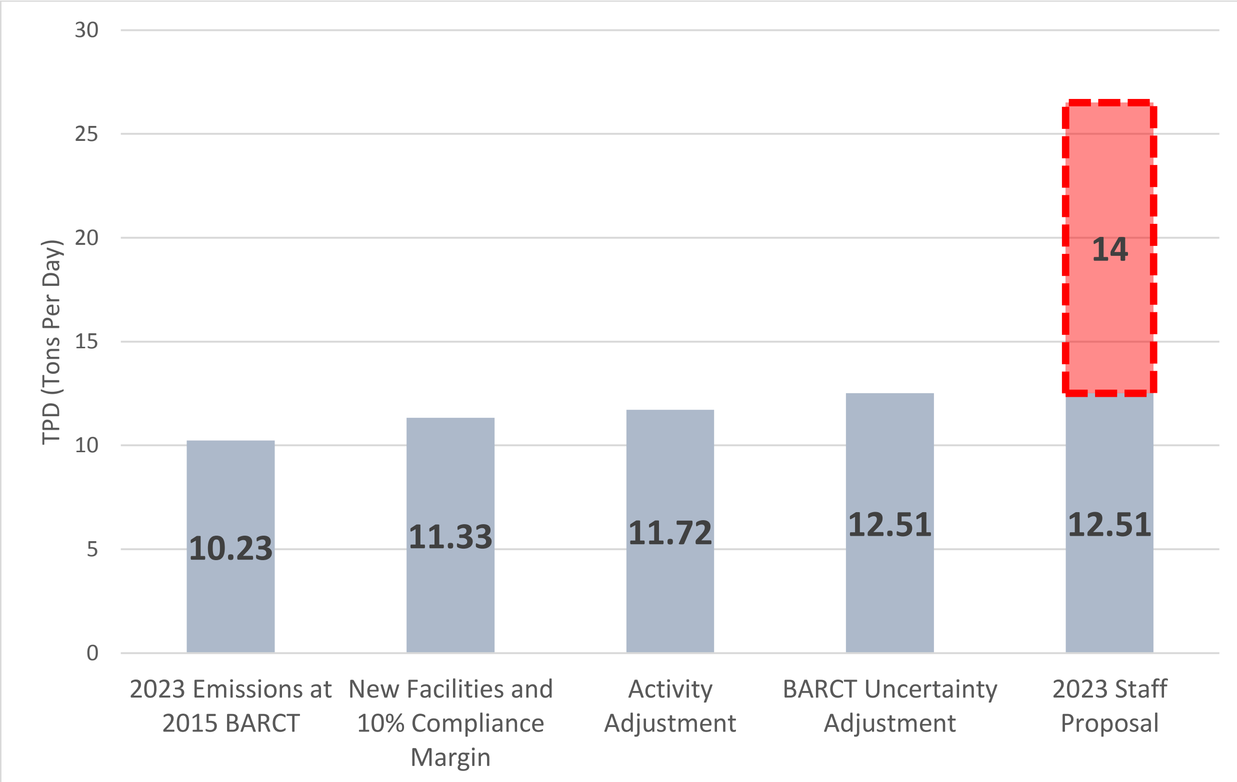
The bottom 10 percent of RTC holders would be exempted from an RTC reduction under the staff proposal. It should be noted that the newer electrical generating facilities among the top 90% of RTC are subject to NSR holding requirements for their equipment, which is mostly at BACT. Staff is proposing a Regional NSR Holding Account for these facilities in order provide some relief given their ongoing NSR obligations of holding RTCs at the equipment's potential to emit level at the beginning of each compliance year.

Staff Proposal

Calculation of Remaining Emissions

The remaining emissions are determined by summing the calculated remaining emissions in 2023 with economic growth factors applied and with BARCT applied for both the refinery and non-refinery sectors (Tables 5.1 and 5.2). The remaining emissions total 10.23 tons per day. Emissions accounting for new RECLAIM facilities since the 2011 base year are added and a 10% compliance margin is applied, so the remaining emissions become 11.33 tons per day. Next, an activity adjustment, accounting for atypical operation conditions in 2011, is applied which results in 11.72 tons per day remaining. Lastly, a BARCT uncertainty adjustment is applied to account for uncertainties in the analysis. After all the adjustments, the total remaining emissions are 12.51 tons per day. This is equivalent to a 14 ton per day reduction from the allocation cap of 26.51 tons per day. Figure U.1 illustrates the adjustments and the total RTC reduction.

Figure U.1 – 2023 Adjustments and Allocation Target



The staff proposal for the shave would affect the top 90 percent of RTC holders, which includes major refinery facilities. Investors would also be shaved at this level. Refineries and Investors are designated as Category A facilities in Table U.1. Non-major refinery facilities in the top 90% of RTC holders and electrical generating facilities among the top 90% of RTC holders would be included in the shave as Category B1 and B2 facilities, respectively. The reductions for the facilities subject to the shave would be weighted by the BARCT reduction contribution for major refineries and all other facilities, with investors grouped with the major refineries. RTC holdings for major refineries and investors would be shaved by 66 percent. For non-major refineries and all other facilities among the top 90 percent of RTC holders, the RTC holdings would be shaved by 49 percent. See Tables U.1 and U.2.

Table U.1 - List of 56 Affected Facilities Plus Investors

HOLDINGS AS SEPTEMBER 22, 2015
USING TOP 90% RTC HOLDINGS LIST FROM 3/20/15

ID	Name	Category
148553	VERNON CITY, LIGHT & POWER DEPARTMENT	A
700144	OLDUVAI GORGE, LLC	A
700161	KOCH SUPPLY & TRADING, LP	A
700084	SHELL NORTH AMERICA (US), L.P.	A
16352	SO CAL EDISON CO	A
158300	CITY OF ONTARIO	A
710	TEXACO EXPLORATION & PRODUCTION INC.	A
700050	KEN BARKER	A
800042	ECO PETR INC (EIS USE ONLY)	A
101337	NATIONAL OFFSETS	A
800253	UNION CARBIDE CORP	A
169514	TITAN TERMINAL AND TRANSPORT INC	A
700170	ABATEMENT CAPITAL LLC	A
700175	TWIN EAGLE RESOURCE MANAGEMENT LLC	A
700177	GREY EPOCH LLC	A
800030	CHEVRON PRODUCTS CO.	A
800089	EXXONMOBIL OIL CORPORATION	A
174655	TESORO REFINING & MARKETING CO, LLC	A
800436	TESORO REFINING AND MARKETING CO, LLC	A
171107	PHILLIPS 66 CO/LA REFINERY WILMINGTON PL	A
800026	ULTRAMAR INC	A
166073	BETA OFFSHORE	B1
800128	SO CAL GAS CO	B1
46268	CALIFORNIA STEEL INDUSTRIES INC	B1
171109	PHILLIPS 66 COMPANY/LOS ANGELES REFINERY	A
174591	TESORO REFINING & MARKETING CO LLC, CAL	A
169754	OXY USA INC	B1
7427	OWENS-BROCKWAY GLASS CONTAINER INC	B1
18931	TAMCO	B1
800183	PARAMOUNT PETR CORP	B1
43201	SNOW SUMMIT INC	B1
172005	NEW- INDY ONTARIO, LLC	B1
800189	DISNEYLAND RESORT	B1
156741	HARBOR COGENERATION CO, LLC	B1
151798	TESORO REFINING AND MARKETING CO, LLC	A
11435	PQ CORPORATION	B1

4242	SAN DIEGO GAS & ELECTRIC	B1
17953	PACIFIC CLAY PRODUCTS INC	B1
800127	SO CAL GAS CO	B1
180367	LINN OPERATING, INC	B1
124838	EXIDE TECHNOLOGIES	B1
800181	CALIFORNIA PORTLAND CEMENT CO	B1
51620	WHEELABRATOR NORWALK ENERGY CO INC	B1
5973	SO CAL GAS CO	B1
3968	TABC, INC	B1
8582	SO CAL GAS CO/PLAYA DEL REY STORAGE FACI	B1
178639	ECO SERVICES OPERATIONS LLC	B1
800153	US GOVT, NAVY DEPT LB SHIPYARD	B1
8547	QUEMETCO INC	B1
1073	BORAL ROOFING LLC	B1
115394	AES ALAMITOS, LLC	B2
115663	EL SEGUNDO POWER, LLC	B2
800074	LA CITY, DWP HAYNES GENERATING STATION	B2
800075	LA CITY, DWP SCATTERGOOD GENERATING STN	B2
115536	AES REDONDO BEACH, LLC	B2
160437	SOUTHERN CALIFORNIA EDISON	B2
115315	NRG CALIFORNIA SOUTH LP, ETIWANDA GEN ST	B2
152707	CPV SENTINEL LLC	B2
115389	AES HUNTINGTON BEACH, LLC	B2
4477	SO CAL EDISON CO	B2
146536	WALNUT CREEK ENERGY, LLC	B2
128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA	B2
115314	LONG BEACH GENERATION, LLC	B2
153992	CANYON POWER PLANT	B2
800193	LA CITY, DWP VALLEY GENERATING STATION	B2
25638	BURBANK CITY, BURBANK WATER & POWER	B2
800168	PASADENA CITY, DWP	B2
155474	BICENT (CALIFORNIA) MALBURG LLC	B2
127299	WILDFLOWER ENERGY LP/INDIGO GEN., LLC	B2
129816	INLAND EMPIRE ENERGY CENTER, LLC	B2
700126	GENERAL ELECTRIC COMPANY	B2

COUNTS

Category	Description	
A	Major Refineries	9
A	Investors (Counted as 1 Facility)	1
B1	Top 90% Holder, Non-Electrical Generating Facilities	26
B2	Top 90% Holder, Electrical Generating Facilities	21
TOTAL		57

Table U.2 - RTC Reduction Calculation

Refinery Reductions Beyond 2005 BARCT, tpd	6.00
Non-Refinery Reductions Beyond 2005 BARCT, tpd	2.77
Total, tpd	8.77

Refinery Contribution to Emission Reduction (6.00 / 8.77 x 100)	68%
Non-Refinery Contribution to Emission Reduction (2.77 / 8.77 x 100)	32%

Total RTC Allocation in 2023	26.51
Remaining 2023 Emissions After BARCT and Growth	11.72
Minus BARCT Uncertainty Adjustment	0.79
Total RTC Reduction (26.51 - 11.72 - 0.79)	14

Weighted Reduction for Refinery (14.00 x 68%)	9.58
Weighted Reduction for Non-Refinery (14.00 x 32%)	4.42
Total Reduction	14

Major Refinery + Investor Holdings for Top 90%	14.57
Non-Major Facility Holdings + All Electrical Generating Facility Holdings for Top 90%	9.09
RTC Holdings for Top 90% of Holders, Including Investors (14.57 + 9.19)	23.66

Remaining Major Refinery + Investor RTC Holdings (14.57 - 9.58)	4.99
% Shave to this Sub-Universe (9.58 / 14.57) x 100	66%

Remaining Non-Refinery RTC Holdings (9.09 - 4.42)	4.67
% Shave to this Sub-Universe (4.42 / 9.09) x 100	49%

RTC Reductions = Current Holdings (26.51 tpd) – Remaining Emissions in 2023 (11.72 tpd) = 14.79 tpd
Total RTC Reductions = 14.79 tpd – (BARCT adjustment of 0.79 tpd) = 14 tpd

CEQA Alternatives

CEQA Alternative 1: This approach would be an across the board RTC reduction and would affect all RECLAIM facilities and investors. The RTC holdings would be shaved by 53 percent overall.

CEQA Alternative 2: This approach, the most stringent, would also be an across the board RTC reduction affecting all RECLAIM facilities and investors, but would not include the 10 percent compliance margin or the BARCT adjustment for refinery equipment. The total RTC reduction would be 15.82 tons per day under this approach and the RTC holdings would be shaved by 60 percent overall.

CEQA Alternative 3: This approach has been proposed by industry representatives and is an across the board shave that would affect all RECLAIM facilities and investors. For this calculation, the base year emissions at the proposed BARCT level would be subtracted from the base year emissions at the previous BARCT level (Year 2000 or 2005). The result would be an RTC reduction of 33 percent to all RECLAIM facilities and investors.

CEQA Alternative 4: This is the "No Project" approach and no RTC reduction would be applied to any RECLAIM facility or investor.

CEQA Alternative 5: This approach would affect all RECLAIM facilities and investors. The RTC reductions would be weighted by the BARCT reduction contribution for major refineries and all other facilities, with investors grouped with the major refineries. RTC holdings for major refineries and investors would be shaved by 66 percent. For non-major refineries and all other facilities, the RTC holdings would be shaved by 37 percent.

Table U.3 - NOx RECLAIM Shave Options and CEQA Alternatives

		Major Refineries/ Investors	Non-Major Facilities	Electrical Generating Facilities	Bottom 10% of Holders
	Staff Proposal Under Consideration				
Staff Proposal	**Shave applied to 90% of RTC Holders (Weighted by BARCT Reduction Contribution)** *56 total facilities, plus investors as 1 company, and includes 47 non-major refinery facilities*	**67%** **(9 Facilities)**	**46%** **(26 Facilities)**	**46%** **(21 Facilities)**	**0%** **(219 Facilities)**
	CEQA Alternatives Under Consideration				
CEQA Alternative #1	**Across the Board** *Affects all facilities and investors*	**53%**	**53%**	**53%**	**53%**
CEQA Alternative #2	**Most Stringent Approach** *Across the Board without 10% Compliance Margin*	**60%**	**60%**	**60%**	**60%**
CEQA Alternative #3	**Industry Approach** *Across the Board: Difference between previous BARCT and new BARCT*	**33%**	**33%**	**33%**	**33%**
CEQA Alternative #4	**No Project**	**0%**	**0%**	**0%**	**0%**
CEQA Alternative #5	**Weighted by BARCT Reduction Contribution** *Affects all facilities and investors*	**66%**	**37%**	**37%**	**37%**

Tradable/Usable and Non-Tradable/Non-Usable Factors in Rule 2002(f)(1)(B) and (C)

The Tradable/Usable NOx Adjustment Factor is derived by dividing the amount of RTCs remaining after the shave for each compliance year by the total holdings prior to the beginning of the shave (September 22, 2015). For those facilities subject to subparagraph (f)(1)(B) [listed in Rule 2002 Table 7] the total Infinite Year Block (IYB) total holdings in 2022 prior to the beginning of the shave is 14.57 tons per day. Similarly, for those facilities subject to subparagraph (f)(1)(C) [listed in Rule 2002 Table 8] the total holdings prior to the beginning of the shave is 9.09 tons per day. Both of these values are presented in Table U.2 of this report.

The proposed RTC reduction for each compliance year is presented in Chapter 5 of this report are:

2016: 4 tons per day
2017: 0 tons per day
2018: 2 tons per day
2019: 2 tons per day
2020: 2 tons per day
2021: 2 tons per day
2022 2 tons per day

The proportion of RTC reductions based on initial holdings and remaining RTC for the Table 7 and Table 8 facilities are as follows:

Compliance Year	Table 7 Facilities		Table 8 Facilities	
	Reductions (TPD)	A_i Remaining (TPD)	Reductions (TPD)	B_i Remaining (TPD)
2016:	2.74	11.83	1.26	7.82
2017:	0	11.83	0	7.82
2018:	1.37	10.46	0.63	7.20
2019:	1.36	9.11	0.64	6.56
2020:	1.37	7.74	0.63	5.93
2021:	1.37	6.37	0.64	5.30
2022	1.38	4.99	0.63	4.67

The Tradable/Usable NOx Adjustment Factor is calculated as follows:

Table 7 Facilities = A_i/14.57

Table 8 Facilities = B_i/9.09

The Non-tradable/Non-usable NOx Adjustment Factor is derived by dividing the annual amount of RTC reductions starting in 2016 by the total holdings prior to the beginning of the shave. For the Table 7 and 8 facilities the annual amount of Non-tradable/Non-Usable holdings would be as follows:

Compliance Year	**Table 7 Facilities RTC Reductions**		**Table 8 Facilities RTC Reductions**	
	Annual (C_i) (TPD)	**Adjustment Factor**	**Annual (D_i) (TPD)**	**Adjustment Factor**
2015	0	0	0	0
2016	2.74	0.188	1.26	0.139
2017	0	0	0	0
2018:	1.37	0.094	0.63	0.069
2019:	1.37	0.093	0.63	0.07
2020:	1.37	0.094	0.63	0.069
2021:	1.37	0.094	0.63	0.07
2022	1.37	0.094	0.63	0.069
2023 and after	0	0	0	0

The Non-tradable/Non-usable NOx Adjustment Factor is calculated as follows:

Table 7 Facilities = $C_i/14.57$

Table 8 Facilities = $D_i/9.09$

Regional NSR Holding Account

In addition to the Non-tradable/Non-usable account, newer electrical generating facilities subject to the shave with ongoing NSR holding requirements (entered RECLAIM after October 15, 1993) will have access to this account under specific circumstances, which will be funded by the shaved portion of each affected facility's holdings for every compliance year of the shave beginning in 2017. At the end of the shave, 49% of the holdings from newer electrical generating facilities subject to NSR requirements will be held in the Regional account. For the first year of the shave, however, there will be no portion that will go into the account. The funding will begin on the second year, when the non-tradable account holdings expire. Access to credits for the purposes of NSR or compliance with annual emissions in the first year of the shave will be provided by the non-tradable account if the rolling average RTC threshold price trigger is reached or in a State of Emergency for power generation declared by the Governor in the Basin. The table below contains the yearly and cumulative holdings that will go into the account:

Compliance Year	Holdings for Regional NSR Holding Account (tpd)	Cumulative Balance (tpd)
2016	0	0
2017	0.237	0.237
2018	0	0.237
2019	0.118	0.355
2020	0.118	0.473
2021	0.118	0.591
2022	0.118	0.709
2023+	0.118	0.827

The total holdings that will be contained in the Regional NSR Holding Account programmatically will be 0.83 tons per day in 2023 and beyond.

The list of electrical generating facilities in the top 90% of RTC holders that are subject to NSR holding requirements and are eligible to use the Regional Account for NSR purposes are as follows:

Facility ID	Facility Name
160437	SOUTHERN CALIFORNIA EDISON
152707	CPV SENTINEL LLC
146536	WALNUT CREEK ENERGY, LLC
128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA
115314	LONG BEACH GENERATION, LLC
153992	CANYON POWER PLANT
155474	BICENT (CALIFORNIA) MALBURG LLC
127299	WILDFLOWER ENERGY LP/INDIGO GEN., LLC
129816/ 700126	INLAND EMPIRE ENERGY CENTER, LLC/ GENERAL ELECTRIC COMPANY

Table 9 in Rule 2002 lists these facilities and the specific yearly RTC balances that will go to the Regional NSR Holding account from compliance year 2016 and beyond. In 2023, the account would reach full funding and will carry over every year for the purposes of fully or partially fulfilling each facility's NSR demonstration.

Appendix V – 2011 Audited Emissions of 20 tons per day

The 2011 audited NOx emissions for the 281 facilities in RECLAIM are shown in Table V-1.

Table V. 1 - 2011 Audited Emissions

			2011 Emissions (lbs)	2011 Emissions (tpd)
1	131003	BP WEST COAST PROD.LLC BP CARSON REF.	1,231,852	1.69
2	131249	BP WEST COAST PRODUCTS LLC,BP WILMINGTON	407,394	0.56
3	151798	TESORO REFINING AND MARKETING CO, LLC	93,488	0.13
4	171107	PHILLIPS 66 CO/LA REFINERY WILMINGTON PL	1,143,902	1.57
5	171109	PHILLIPS 66 COMPANY/LOS ANGELES REFINERY	673,652	0.92
6	800026	ULTRAMAR INC (NSR USE ONLY)	534,363	0.73
7	800030	CHEVRON PRODUCTS CO.	1,425,393	1.95
8	800089	EXXONMOBIL OIL CORPORATION	1,602,233	2.19
9	800183	PARAMOUNT PETR CORP (EIS USE)	104,249	0.14
10	800436	TESORO REFINING AND MARKETING CO, LLC	1,171,965	1.61
		Total Refineries		**11.49**
1	4242	SAN DIEGO GAS & ELECTRIC	142,751	0.20
2	4477	SO CAL EDISON CO	137,290	0.19
3	5973	SO CAL GAS CO	88,258	0.12
4	7427	OWENS-BROCKWAY GLASS CONTAINER INC	135,486	0.19
5	11435	PQ CORPORATION	81,270	0.11
6	15504	SCHLOSSER FORGE COMPANY	52,331	0.07
7	18931	TAMCO	226,012	0.31
8	22911	CARLTON FORGE WORKS	48,839	0.07
9	46268	CALIFORNIA STEEL INDUSTRIES INC	464,990	0.64
10	51620	WHEELABRATOR NORWALK ENERGY CO INC	89,025	0.12
11	114801	RHODIA INC.	48,878	0.07
12	115389	AES HUNTINGTON BEACH, LLC	98,993	0.14
13	115394	AES ALAMITOS, LLC	80,929	0.11
14	119907	BERRY PETROLEUM COMPANY	131,857	0.18
15	124838	EXIDE TECHNOLOGIES	62,824	0.09
16	128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA	49,983	0.07
17	129497	THUMS LONG BEACH CO	66,364	0.09
18	129816	INLAND EMPIRE ENERGY CENTER, LLC	105,857	0.15
19	160437	SOUTHERN CALIFORNIA EDISON	204,132	0.28
20	166073	BETA OFFSHORE	391,977	0.54
21	171960	TIN, INC. DBA INTERNATIONAL PAPER	327,637	0.45
22	800074	LA CITY, DWP HAYNES GENERATING STATION	205,022	0.28
23	800075	LA CITY, DWP SCATTERGOOD GENERATING STN	103,988	0.14
24	800128	SO CAL GAS CO (EIS USE)	461,243	0.63
25	800193	LA CITY, DWP VALLEY GENERATING STATION	166,413	0.23
26	800330	THUMS LONG BEACH	49,657	0.07
27	800335	LA CITY, DEPT OF AIRPORTS	73,245	0.10
		Total non-refineries		**5.61**
		Total for top 37 emitting facilities		**17.10**

1	800189	DISNEYLAND RESORT	47,216	0.06
2	8547	QUEMETCO INC	46,831	0.06
3	126498	STEELSCAPE, INC	46,420	0.06
4	101656	AIR PRODUCTS AND CHEMICALS, INC.	44,275	0.06
5	8582	SO CAL GAS CO/PLAYA DEL REY STORAGE FACI	42,884	0.06
6	800168	PASADENA CITY, DWP (EIS USE)	41,370	0.06
7	115536	AES REDONDO BEACH, LLC	40,890	0.06
8	9755	UNITED AIRLINES INC	40,626	0.06
9	94872	METAL CONTAINER CORP	39,730	0.05
10	800080	LUNDAY-THAGARD COMPANY	39,275	0.05
11	155474	BICENT (CALIFORNIA) MALBURG LLC	38,772	0.05
12	105903	PRIME WHEEL	37,852	0.05
13	43436	TST, INC.	35,778	0.05
14	148236	AIR LIQUIDE LARGE INDUSTRIES U.S., LP	33,031	0.05
15	3417	AIR PROD & CHEM INC	32,660	0.04
16	14495	VISTA METALS CORPORATION	30,433	0.04
17	139010	RIPON COGENERATION LLC	30,419	0.04
18	16639	SHULTZ STEEL CO	30,415	0.04
19	47781	OLS ENERGY-CHINO	29,938	0.04
20	550	LA CO., INTERNAL SERVICE DEPT	29,202	0.04
21	118406	CARSON COGENERATION COMPANY	28,760	0.04
22	155877	MILLERCOORS, LLC	28,439	0.04
23	800409	NORTHROP GRUMMAN SYSTEMS CORPORATION	27,489	0.04
24	800037	DEMENNO/KERDOON	26,951	0.04
25	16338	KAISER ALUMINUM FABRICATED PRODUCTS, LLC	25,667	0.04
1	136	PRESS FORGE CO	25,407	0.03
2	3704	ALL AMERICAN ASPHALT, UNIT NO.01	24,416	0.03
3	16642	ANHEUSER-BUSCH LLC., (LA BREWERY)	23,205	0.03
4	35302	OWENS CORNING ROOFING AND ASPHALT, LLC	23,022	0.03
5	800170	LA CITY, DWP HARBOR GENERATING STATION	22,609	0.03
6	115663	EL SEGUNDO POWER, LLC	21,639	0.03
7	11887	NASA JET PROPULSION LAB	21,140	0.03
8	153992	CANYON POWER PLANT	21,077	0.03
9	17953	PACIFIC CLAY PRODUCTS INC	20,635	0.03
10	346	FRITO-LAY, INC.	20,492	0.03
11	68042	CORONA ENERGY PARTNERS, LTD	19,286	0.03
12	18294	NORTHROP GRUMMAN CORP, AIRCRAFT DIV	18,299	0.03
13	3585	R. R. DONNELLEY & SONS CO, LA MFG DIV	16,710	0.02
14	800016	BAKER COMMODITIES INC	16,616	0.02
15	12428	NEW NGC, INC.	16,418	0.02
16	7411	DAVIS WIRE CORP	16,090	0.02
17	83102	LIGHT METALS INC	15,731	0.02
18	54402	SIERRA ALUMINUM COMPANY	15,677	0.02
19	117785	BALL METAL BEVERAGE CONTAINER CORP.	15,323	0.02
20	117290	B BRAUN MEDICAL, INC	15,167	0.02
21	151532	LINN OPERATING, INC	15,146	0.02
22	800408	NORTHROP GRUMMAN SYSTEMS	14,835	0.02
23	52517	REXAM BEVERAGE CAN COMPANY	14,827	0.02

24	115172	RAYTHEON COMPANY	14,365	0.02
25	21887	KIMBERLY-CLARK WORLDWIDE INC.-FULT. MILL	14,070	0.02
26	800088	3M COMPANY	13,446	0.02
27	800113	ROHR, INC.	12,593	0.02
28	115563	NCI GROUP INC., DBA, METAL COATERS OF CA	12,471	0.02
29	115314	LONG BEACH PEAKERS LLC	12,363	0.02
30	1073	BORAL ROOFING LLC	12,063	0.02
31	23752	AEROCRAFT HEAT TREATING CO INC	11,919	0.02
32	45746	PABCO BLDG PRODUCTS LLC,PABCO PAPER, DBA	11,885	0.02
33	3029	MATCHMASTER DYEING & FINISHING INC	11,691	0.02
34	127299	WILDFLOWER ENERGY LP/INDIGO GEN., LLC	11,529	0.02
35	43201	SNOW SUMMIT INC	11,028	0.02
36	800066	HITCO CARBON COMPOSITES INC	10,783	0.01
37	115315	GEN ON WEST, LP	10,625	0.01
38	61962	LA CITY, HARBOR DEPT	10,436	0.01
39	9053	VEOLIA ENERGY LOS ANGELES, INC	10,120	0.01
40	53729	TREND OFFSET PRINTING SERVICES, INC	10,005	0.01
41	97081	THE TERMO COMPANY	9,943	0.01
42	85943	SIERRA ALUMINUM COMPANY	9,856	0.01
43	22364	ITT CORPORATION	9,853	0.01
44	45471	O N I S, DBA, CARMEUSE INDUSTRIAL SANDS	9,784	0.01
45	800393	VALERO WILMINGTON ASPHALT PLANT	9,556	0.01
46	16978	CLOUGHERTY PACKING LLC/HORMEL FOODS CORP	9,424	0.01
47	61722	RICOH ELECTRONICS INC	9,200	0.01
48	22607	CALIFORNIA DAIRIES, INC	9,148	0.01
49	115241	BOEING SATELLITE SYSTEMS INC	9,142	0.01
50	101977	SIGNAL HILL PETROLEUM INC	8,791	0.01
51	131732	NEWPORT FAB, LLC	8,769	0.01
52	21598	ANGELICA TEXTILE SERVICES	8,675	0.01
53	139796	CITY OF RIVERSIDE PUBLIC UTILITIES DEPT	8,579	0.01
54	123774	HERAEUS PRECIOUS METALS NO. AMERICA, LLC	8,552	0.01
55	16737	ATKINSON BRICK CO	8,448	0.01
56	145836	AMERICAN APPAREL DYEING & FINISHING, INC	8,416	0.01
57	130211	PAPER-PAK INDUSTRIES	8,385	0.01
58	132068	BIMBO BAKERIES USA INC	8,379	0.01
59	800372	EQUILON ENTER. LLC, SHELL OIL PROD. US	8,284	0.01
60	157359	HENKEL ELECTRONIC MATERIALS, LLC	7,990	0.01
61	800196	AMERICAN AIRLINES INC (EIS USE)	7,985	0.01
62	115130	VERTIS, INC	7,890	0.01
63	37603	SGL TECHNIC INC, POLYCARBON DIVISION	7,638	0.01
64	19390	SULLY-MILLER CONTRACTING CO.	7,459	0.01
65	38872	MARS PETCARE U.S., INC.	7,248	0.01
66	131850	SHAW DIVERSIFIED SERVICES INC	7,207	0.01
67	3721	DART CONTAINER CORP OF CALIFORNIA	7,078	0.01
68	107656	CALMAT CO	7,014	0.01
[illegible]	[illegible]	BURBANK CITY,BURBANK WATER & POWER	[illegible]	0.01

69	56940	CITY OF ANAHEIM/COMB TURBINE GEN STATION	7,004	0.01
70	2825	MCP FOODS INC	6,991	0.01
71	800150	US GOVT, AF DEPT, MARCH AIR RESERVE BASE	6,892	0.01
72	11119	THE GAS CO./ SEMPRA ENERGY	6,820	0.01
73	152501	PRECISION SPECIALTY METALS, INC.	6,773	0.01
74	2912	HOLLIDAY ROCK CO INC	6,761	0.01
75	59618	PACIFIC CONTINENTAL TEXTILES, INC.	6,659	0.01
76	19167	R J NOBLE COMPANY	6,626	0.01
77	40034	BENTLEY PRINCE STREET INC	6,205	0.01
78	25638	BURBANK CITY, BURBANK WATER & POWER	6,137	0.01
79	800038	THE BOEING COMPANY - C17 PROGRAM	6,092	0.01
80	18455	ROYALTY CARPET MILLS INC	5,997	0.01
81	138568	CALIFORNIA DROP FORGE, INC	5,977	0.01
82	114997	RAYTHEON COMPANY	5,819	0.01
83	153199	THE KROGER CO/RALPHS GROCERY CO	5,639	0.01
84	161300	SAPA EXTRUDER, INC	5,600	0.01
85	96587	TEXOLLINI INC	5,573	0.01
86	165192	TRIUMPH AEROSTRUCTURES, LLC	5,464	0.01
87	115277	LAFAYETTE TEXTILE IND LLC	5,409	0.01
88	74424	ANGELICA TEXTILE SERVICES	5,347	0.01
89	137471	GRIFOLS BIOLOGICALS INC	5,246	0.01
90	153033	GEORGIA-PACIFIC CORRUGATED LLC	5,223	0.01
91	12155	ARMSTRONG WORLD INDUSTRIES INC	5,032	0.01
92	73022	US AIRWAYS INC	4,988	0.01
93	107654	CALMAT CO	4,897	0.01
94	156722	AMERICAN APPAREL KNIT AND DYE	4,841	0.01
95	11034	VEOLIA ENERGY LOS ANGELES, INC	4,831	0.01
96	800003	HONEYWELL INTERNATIONAL INC	4,826	0.01
97	141295	LEKOS DYE AND FINISHING, INC	4,686	0.01
98	124619	ARDAGH METAL PACKAGING USA INC.	4,543	0.01
99	155221	SAVE THE QUEEN LLC (DBA QUEEN MARY)	4,224	0.01
100	1744	KIRKHILL - TA COMPANY	4,003	0.01
101	11716	FONTANA PAPER MILLS INC	3,971	0.01
102	800417	PLAINS WEST COAST TERMINALS LLC	3,963	0.01
103	133987	PLAINS EXPLORATION & PRODUCTION CO, LP	3,883	0.01
104	143741	DCOR LLC	3,850	0.01
105	800149	US BORAX INC	3,825	0.01
106	63180	DARLING INTERNATIONAL INC	3,659	0.01
107	148925	CHERRY AEROSPACE	3,634	0.00
108	20604	RALPHS GROCERY CO	3,629	0.00
109	800094	EXXONMOBIL OIL CORPORATION	3,545	0.00
110	20203	RECYCLE TO CONSERVE INC.	3,542	0.00

110	20203	RECYCLE TO CONSERVE INC.	3,542	0.00
111	800067	BOEING SATELLITE SYSTEMS INC	3,409	0.00
112	117140	AOC, LLC	3,247	0.00
113	167066	ARLON GRAPHICS L.L.C.	3,239	0.00
114	5998	ALL AMERICAN ASPHALT	3,235	0.00
115	114264	ALL AMERICAN ASPHALT	3,233	0.00
116	15544	REICHHOLD INC	3,189	0.00
117	800338	SPECIALTY PAPER MILLS INC	3,097	0.00
118	800431	PRATT & WHITNEY ROCKETDYNE, INC.	3,028	0.00
119	17956	WESTERN METAL DECORATING CO	3,023	0.00
120	2946	PACIFIC FORGE INC	2,938	0.00
121	113160	HILTON COSTA MESA	2,936	0.00
122	42630	PRAXAIR INC	2,737	0.00
123	157363	INTERNATIONAL PAPER CO	2,661	0.00
124	107653	CALMAT CO	2,577	0.00
125	17623	LOS ANGELES ATHLETIC CLUB	2,511	0.00
126	50098	D&D DISPOSAL INC,WEST COAST RENDERING CO	2,501	0.00
127	98159	PACIFIC COAST ENERGY COMPANY LP	2,384	0.00
128	125015	LOS ANGELES TIMES COMMUNICATIONS LLC	2,339	0.00
129	95212	FABRICA	2,296	0.00
130	14871	SONOCO PRODUCTS CO	2,291	0.00
131	3968	TABC, INC	2,283	0.00
132	156741	HARBOR COGENERATION CO, LLC	2,277	0.00
133	124808	INEOS POLYPROPYLENE LLC	2,247	0.00
134	112853	NP COGEN INC	2,206	0.00
135	107655	CALMAT CO	2,182	0.00
136	2418	FRUIT GROWERS SUPPLY CO	2,083	0.00
137	94930	CARGILL INC	2,032	0.00
138	133813	EI COLTON, LLC	1,965	0.00
139	14049	MARUCHAN INC	1,949	0.00
140	168088	PCCR USA	1,903	0.00
141	800325	TIDELANDS OIL PRODUCTION CO	1,872	0.00
142	25058	EXXONMOBIL OIL CORP	1,787	0.00
143	800127	SO CAL GAS CO (EIS USE)	1,778	0.00
144	143740	DCOR LLC	1,741	0.00
145	105277	SULLY MILLER CONTRACTING CO	1,740	0.00
146	800181	CALIFORNIA PORTLAND CEMENT CO (NSR USE)	1,727	0.00
147	10094	ATLAS CARPET MILLS INC	1,726	0.00
148	117227	SHCI SM BCH HOTEL LLC, LOEWS SM BCH HOTE	1,724	0.00
149	158950	WINDSOR QUALITY FOOD CO. LTD.	1,701	0.00
150	800420	PLAINS WEST COAST TERMINALS LLC	1,690	0.00
151	42775	WEST NEWPORT OIL CO	1,661	0.00
152	143738	DCOR LLC	1,570	0.00
153	144455	LIFOAM INDUSTRIES, LLC	1,497	0.00
154	164204	CITY OF RIVERSIDE, PUBLIC UTILITIES DEPT	1,476	0.00

155	14736	THE BOEING COMPANY	1,458	0.00
156	169754	OXY USA INC	1,438	0.00
157	800416	PLAINS WEST COAST TERMINALS LLC	1,426	0.00
158	800110	THE BOEING COMPANY	1,369	0.00
159	800371	RAYTHEON SYSTEMS COMPANY - FULLERTON OPS	1,302	0.00
160	111415	VAN CAN COMPANY	1,268	0.00
161	115041	RAYTHEON COMPANY	1,188	0.00
162	800210	CONEXANT SYSTEMS INC	1,166	0.00
163	132071	DEAN FOODS CO. OF CALIFORNIA	1,164	0.00
164	151594	OXY USA, INC	1,132	0.00
165	5814	GAINEY CERAMICS INC	1,126	0.00
166	7416	PRAXAIR INC	1,108	0.00
167	124723	GREKA OIL & GAS, INC	1,025	0.00
168	17344	EXXONMOBIL OIL CORP	977	0.00
169	148340	THE BOEING CO. COMMERCIAL AVIATION SRVCS	950	0.00
170	14926	SEMPRA ENERGY (THE GAS CO)	948	0.00
171	89248	OLD COUNTRY MILLWORK INC	930	0.00
172	129810	CITY OF RIVERSIDE PUBLIC UTILITIES DEPT	866	0.00
173	800205	BANK OF AMERICA NT & SA, BREA CENTER	859	0.00
174	132191	PURENERGY OPERATING SERVICES, LLC	826	0.00
175	68118	TIDELANDS OIL PRODUCTION COMPANY ETAL	823	0.00
176	12372	MISSION CLAY PRODUCTS	787	0.00
177	16660	THE BOEING COMPANY	761	0.00
178	142267	FS PRECISION TECH LLC	739	0.00
179	47771	DELEO CLAY TILE CO INC	657	0.00
180	151899	VINTAGE PRODUCTION CALIFORNIA LLC	645	0.00
181	133996	PLAINS EXPLORATION & PRODUCTION COMPANY	611	0.00
182	14944	CENTRAL WIRE, INC.	564	0.00
183	800264	EDGINGTON OIL COMPANY	481	0.00
184	800182	RIVERSIDE CEMENT CO (EIS USE)	456	0.00
185	800344	CALIFORNIA AIR NATIONAL GUARD, MARCH AFB	425	0.00
186	40483	NELCO PROD. INC	282	0.00
187	160888	HINES REIT EL SEGUNDO, LP	271	0.00
188	125579	DIRECTV	268	0.00
189	9217	VEOLIA ENERGY LOS ANGELES, INC	220	0.00
190	14502	VERNON CITY, LIGHT & POWER DEPT	172	0.00
191	137508	TONOGA INC, TACONIC DBA	93	0.00
192	143739	DCOR LLC	79	0.00
193	2083	SUPERIOR INDUSTRIES INTERNATIONAL INC	75	0.00
194	142536	DRS SENSORS & TARGETING SYSTEMS, INC	72	0.00
195	149491	BOEING REALTY CORP	49	0.00
196	132192	PURENERGY OPERATING SERVICES, LLC	29	0.00
197	800373	CENCO REFINING COMPANY	25	0.00
198	12185	US GYPSUM CO	5	0.00

199	141555	CASTAIC CLAY PRODUCTS, LLC	4	0.00
200	151394	LINN WESTERN OPERATING INC	4	0.00
201	152054	LINN WESTERN OPERATING INC	3	0.00
202	58622	LOS ANGELES COLD STORAGE CO	1	0.00
203	151415	LINN WESTERN OPERATING, INC	1	0.00
204	1634	STEELCASE INC, WESTERN DIV	0	0.00
205	15164	HIGGINS BRICK CO	0	0.00
206	20543	REDCO II	0	0.00
207	23196	SUNKIST GROWERS, INC	0	0.00
208	38440	COOPER & BRAIN - BREA	0	0.00
209	42676	CES PLACERITA INC	0	0.00
210	119104	CALMAT CO	0	0.00
211	137520	PLAINS WEST COAST TERMINALS LLC	0	0.00
212	146536	WALNUT CREEK ENERGY, LLC	0	0.00
213	148896	VINTAGE PRODUCTION CALIFORNIA LLC	0	0.00
214	148897	VINTAGE PRODUCTION CALIFORNIA LLC	0	0.00
215	151601	OXY USA, INC.	0	0.00
216	152707	CPV SENTINEL LLC	0	0.00
217	152857	GEORGIA-PACIFIC GYPSUM LLC	0	0.00
218	800343	BOEING SATELLITE SYSTEMS, INC	0	0.00
219	800419	PLAINS WEST COAST TERMINALS LLC	0	0.00
	TOTAL (281 Facilities by end of June 2011)			**20.006**
	Note: August 29, 2013 data from RECLAIM Admin team			

Appendix W – 2012 Emissions for Power Generating Sector

The base year for the BARCT analysis is compliance year 2011. However, the 2011 base year would not be appropriate for this source category due to the uniqueness of its operations. There have been several changes within recent years that have warranted the use of more recent base year data.

The San Onofre Nuclear Generating Station (SONGS) has not been in operation since early 2012 and is now undergoing decommissioning. The power deficit was to be made up by other natural gas fired units in the region. Other existing units are subject to the once-through-cooling (OTC) regulation and will have to be repowered. These repowered units are predicted to be more efficient units that consume less natural gas to produce the same amount of power as their predecessors. Other trends in the industry have begun to affect power availability such as the increased use of renewable power, like wind, water, and solar. The state of California must meet a 33% Renewable Portfolio Standard by 2020, and the inherent volatility of these renewable energy sources means that gas demand must be met almost in real time.

Based on the 2014 California Gas Report, gas demand in the future is set to decrease slightly due to the utilization of more efficient electrical generating facilities, greenhouse gas (GHG) reductions, and the increased use of renewable power. The projected emissions in 2023 using compliance year 2011 as the base year used growth factors from SCAG (Southern California Association of Governments).

Table W. 1 - Compliance Year 2011 Power Generating Sector Emissions

Compliance Year 2011 Emissions (tpd)	2011 Emissions at BARCT/BACT (tpd)	Growth Factor	2023 Emissions with Growth (tpd)
1.45	2.57	1.146	2.95

The figures above included those electrical generating facilities among the top 37 NOx emitters in compliance year 2011. An additional 0.34 tons per day came from electrical generating facilities outside the top 37 and was included as part of the “Other Sources” category with a different growth factor.

More recent base year data was obtained using calendar year AER (Annual Emissions Report) fuel usage data for 2012. The calendar year 2012 emissions include those for the major sources only belonging to electric generating facility source category (includes boilers, gas turbines, and ICEs). The emissions from process units and any Rule 219 equipment are almost negligible (the emissions from process units in 2011 were 0.006 tpd).

Table W. 2 - 2012 Power Generating Sector Emissions Based on Annual Emission Reports (AER) Fuel Usage

Calendar Year 2012 Emissions (tpd)	2012 Emissions at BARCT/BACT (tpd)	Growth Factor	2023 Emissions with Growth (tpd)
2.50	2.35	0.8683	2.04

The growth factor was extrapolated from the tables in the 2104 California Gas Report and it shows a slight decrease in demand for natural gas. There were nine electrical generating facilities among the top 37 emitters in compliance year 2011. For this updated analysis, all electrical generating facilities in RECLAIM were included (30 in total) and their emissions at the BARCT or BACT level were calculated. Most of the units are already meeting BARCT or BACT requirements, due to previous rule requirements.

Another unique aspect of the power generating sector is that many of the newer units are subject to new source review (NSR) holding requirements. Per Rule 2005, if a facility is new (received all its District permits on or after October 15, 1993), it must hold sufficient RTCs in advance of every year at the equipment's potential to emit level. Virtually all power generating units typically operate at a level far below its potential to emit, but the facility must still hold the RTCs to comply with the NSR demonstration. Stakeholders have brought to SCAQMD staff's attention their concern about the shave and whether a power generating facility can still comply with its emission allocation and NSR demonstration concurrently, especially when there is no cost effective method to retrofit their equipment to generate credits.

SCAQMD staff has proposed a safety valve for addressing the concerns of the power generating sector. A Regional NSR Holding Account has been proposed that would consist of RTCs solely to meet the programmatic NSR holding demonstration. Under this approach, individual facility holding requirements would no longer be necessary. Concerns have also been raised in the event that a power emergency is experienced and there is an added demand for power production. SCAQMD staff has also proposed to allow access to the Regional NSR Holding Account if the Governor declares a state of emergency.

Appendix X – Proposed Changes in Rules 2002, 2005, 2011 and 2012

Rule 2002

The purpose of Rule 2002 is to establish the methodology for calculating facility Allocations and adjustments to RTC holdings for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx).

Rule 2002 provides an overview of the RECLAIM Allocations; the establishment of starting, year 2000 and 2003 Allocations, the annual Allocations for NOx and SOx and the adjustments to RTC holdings. Rule 2002 also specifies the requirement for establishing High Employment/Low Emissions (HILO) facilities, Non-Tradable Allocation Credits, and RTC Reduction Exemptions. In addition to these sections of the rule there are various tables specifying RECLAIM equipment emission factors and the identification of certain facilities status with regards to the RECLAIM Allocation adjustment.

The most substantive proposed rule amendments are found in subdivision (f) *Annual Allocations for NOx and SOx and Adjustments to RTC Holdings* as well as the additions of Table 7 - *List of NOx RECLAIM Facilities Referenced in Subparagraph (f)(1)(B)*, Table 8 - *List of NOx RECLAIM Facilities Referenced in Subparagraph (f)(1)(C)*, and Table 9 - *List of NOx RECLAIM Facilities for the Regional NSR Holding Account with Balances (in lbs)*. Staff is also proposing to remove subdivision (i) *RTC Reduction Exemption* from the Rule 2002.

The staff proposal calls for a programmatic reduction of 14 tons per day. Four tons per day would be reduced in 2016 and the remainder would be reduced in equal increments of 2 tons per day from 2018 to 2022. There would be no reductions proposed for the year 2017. These reductions are reflected in subparagraphs (f)(1)(B) and (f)(1)(C). Subparagraph (f)(1)(B) includes all of Major Refineries and Investors. The Major Refineries are listed in Table 7 of Rule 2002. Subparagraph (f)(1)(C) includes all other facilities subject to reductions in NOx RTCs. These facilities are listed in Table 8 of Rule 2002. These adjustment factors would also apply to subsequent owners of any of these facilities.

Thus the remaining NOx RTCs after a shave for any compliance year would be the Tradable/Usable NOx RTC Adjustment factor in (f)(1)(B) multiplied by the RTC holdings (as of September 22, 2015) of all the Major Refineries and Investors listed in Table 7 plus the Tradable/Usable NOx RTC Adjustment factor in (f)(1)(C) multiplied by the RTC holdings (as of September 22, 2015) of all the facilities listed in Table 8.

Since the RTC reductions specified in subparagraph (f)(1)(A) have been realized the conversion of non-tradable/non-usable NOx RTCs to tradable/usable NOx RTCs is no longer applicable to the RTC reductions specified in this subparagraph. The tradable/usable NOx RTCs specified in subparagraph (f)(1)(A) would remain intact and used for calculating RTC reductions for facilities entering the RECLAIM program. However, a similar approach in applying adjustment factors previously specified in subparagraph (f)(1)(A) would now be applied to the RTC reductions specified in subparagraphs (f)(1)(B) and (f)(1)(C).

Many of the proposed amendments to Rule 2002 focus on what will be done to provide access to RTCs to affected electrical generating facilities in the RECLAIM program under a State of Emergency related to electricity demand or power grid stability in the Basin. Other amendments focus on providing relief from burdensome New Source Review (NSR) holding requirement for newer electrical generating facilities that entered RECLAIM after 1993.

New electrical generating facilities must hold sufficient RTCs to offset emission increases for one year prior to commencement of operation and at the beginning of every compliance year thereafter. These requirements are triggered in cases where a facility incurs an emission increase as defined under Rule 2005(d) – Emission Increase. Staff has identified ten (10) new electrical generating facilities subject to this requirement. These facilities are listed in Table 9 of Rule 2002. Staff is providing in Table 9 the quantity of NOx RTCs commensurate to the shave amount for these ten new electrical generating facilities. These RTCs would be placed in a Regional NSR Holding Account as per (f)(1)G) for the specific purpose of helping to comply with the requirements specified in Rule 2005.

According to subparagraph (f)(1)(F), at the conclusion of any of the compliance years 2016 through 2022 if the NOx RTC prices have not exceeded the proposed $22,500 per ton threshold as specified in subparagraph (f)(1)(I) and a State of Emergency related to electricity demand or power grid stability in the Basin as specified in paragraph (f)(4) has not been declared by the Governor, then the Non-tradable/Non-usable NOx RTCs for that compliance year, except for those RTCs specified in subparagraph (f)(1)(G), shall be submitted as part of the State Implementation Plan commitment. According to subparagraph (f)(1)(G) the Executive Officer will transfer to a Regional NSR Holding account the amount of NOx RTCs holdings listed in Table 9 of this Rule from the corresponding facilities identified in the same table..

The threshold of $15,000 per ton has been updated to $22,500 per ton, consistent with the cost-effectiveness threshold for additional analysis in the 2012 AQMP. (*2012 AQMP, Chapter 4: Control Strategy and Implementation, page 4-43*)

A companion provision to the abovementioned subparagraphs is subparagraph (f)(1)(H) which states that for the purposes of meeting the NSR holding requirement as specified in subdivision (f) of Rule 2005, the facilities identified in Table 9 may use a combination of their Tradable/Usable and Non-tradable/Non-usable RTCs specified in subparagraph (f)(1)(C) and the amount for each facility listed in Table 9 which represent the RTCs in the Regional NSR Holding account.

Other than the updated price trigger, other proposed changes to subparagraph (f)(1)(I) require the Executive Officer to include in his report to the Governing Board a commitment and schedule to conduct a more rigorous analysis of the RECLAIM program.

The deletion of subparagraph (f)(1)(D) [existing rule designation] and proposed changes to subparagraphs (f)(1)(K) and (f)(1)(L) reflect the change from using the adjustment factors in (f)(1)(A) [previous NOx RECLAIM amendment] to the adjustment factors applied in this proposed amendment, as well as updated methods for determining allocations for existing facilities that enter RECLAIM.

The addition of paragraph (f)(4) describes provisions to convert Non-tradable/Non-usable RTCS and the Regional NSR Holding Account during a State of Emergency declared by the Governor related to electricity demand or power grid stability in the Basin. Specifically, such as a State of Emergency, the current compliance year Non-tradable/Non-usable NOx RTCs held by any electrical generating facilities that generate and distribute electricity to the grid system affected by the State of Emergency may be used to offset emissions after completely exhausting their own Tradable/Usable NOx RTCs.

If such a facility has completely exhausted their Non-tradable/Non-usable NOx RTCs, the owner or operator of the facility may apply for the use of the NOx RTCs in the Regional NSR Holding Account. The use of such RTCs in this Account would be based on availability at the end of each quarter. The owner or operator of each electrical generating facility requesting NOx RTCs from the Regional NSR Holding Account would be required to submit a written request to the Executive Officer specifying the amount of RTCs needed and the basis for requesting the required amount.

The Executive Officer will determine the amount and distribution of the NOx RTCs from the Regional NSR Holding Account based on the requesting facility meeting the following criteria:

(i) The State of Emergency related to electricity demand or power grid stability in the Basin, as declared by the Governor, was the direct cause of the excess emissions.

(ii) The facility has been ordered to generate electricity in an increased amount and/or frequency due to the State of Emergency.

(iii) The facility has adequately demonstrated their need for the specific amount of RTCs from the Regional NSR Holding Account.

(iv) The facility owner or operator has not sold any part of their RTC holdings for the subject compliance year.

If the total RTCs requested exceed the supply of RTCs in this Account, the RTCs will be distributed proportionately according to the offset needs of the facilities on a quarterly basis. These RTCs will be non-tradable, but usable to offset emissions.

According to paragraph (f)(5) the Executive Officer will report to the Governing Board within 60 days of the State of Emergency declaration by the Governor related to electricity demand or power grid stability in the Basin. Included in this report will be, as applicable:

(i) the quantity of RTCs from the Regional NSR Holding Account that were distributed for compliance with the requirement to reconcile quarterly and annual emissions;

(ii) any adverse impacts that the State of Emergency is having on the RECLAIM program; and

(iii) any potential changes to the RECLAIM program that will be needed to help correct these impacts.

There has also been some changes to paragraph (f)(1)(L) that pertain to NOx Allocations for existing facilities that enter RECLAIM after the date of adoption. For this rule provision for Compliance Year 2016 and all subsequent years the amount determined pursuant to subparagraph (d)(1)(A) except the variable B2 shall be the lowest of:

(i) The applicable 2000 (Tier I) Ending Emission Factor for the subject source(s) or process unit(s), as specified in Table 1 multiplied by the percentage inventory adjustment pursuant to subdivision (e) (0.72);
(ii) The BARCT Emission factor for the subject source as specified in Table 3; and
(iii) The proposed BARCT Emission factor for the subject as specified in Table 6.

Rule 2005

Rule 2005 sets forth requirements for new or modified equipment or processes at RECLAIM facilities. The purpose of the rule is to ensure that the RECLAIM program is equivalent to the federal and state NSR program requirements. Rule 2005 provides three separate requirements to meet the NSR programmatic equivalency:

1) Sources causing emission increases must be equipped with Best Available Control Technology (BACT),

2) Modeling must be used to demonstrate that operation of the source will not result in a significant increase in the air quality concentration of nitrogen dioxide (NO_2) if the facility total emissions exceed its 1994 starting allocations plus non-tradable credits, and

3) The facility must hold sufficient RTCs to offset emission increases for one year prior to commencement of operation and at the beginning of every compliance year thereafter.

These requirements are triggered in cases where a facility incurs an emission increase as defined under Rule 2005(d) – Emission Increase. The evaluation of emission increases under this paragraph is defined on a device-by-device basis at the maximum potential to emit. Any time a new NOx- (or SOx)-emitting RECLAIM device is installed, it triggers the credit holding requirements because it does not have any prior emissions, even in cases where the new device is replacing an older, dirtier device.

Among these requirements, the credit holding requirement ensures that the facility has adequate credits to offset emission increases year-by-year. It does not directly require emission decreases. On the other hand, all RECLAIM facilities are required to reconcile their Allocations to their emissions (i.e. hold enough RTCs to cover their emissions) by the end of each quarter and each compliance year pursuant to Rule 2004 – Requirements. Therefore, under RECLAIM, all facilities are required to have credits to offset all RECLAIM emissions regardless if they are subject to the requirements of Rule 2005.

The amendments made in June 3, 2011 required an existing RECLAIM facility to hold adequate RTCs for the first year of operation prior to commencement of operation of a new or modified source, but will not require the facility to hold RTCs at the commencement of subsequent compliance years, provided that the facility emission level remains below its starting Allocations plus non-tradable credits.

The offset requirements for new RECLAIM facilities remained unchanged. Thus a new facility will have to continue to hold adequate RTCs equal to the amount of emission increases at the beginning of each compliance year. Any unused RTCs cannot be sold until the end of the compliance year, or the applicable quarters if the facility has permit conditions to cap its emissions during each quarter, thus allowing sale of unused RTCs at the end of the quarter.

To help in remedying this holding requirement for new electrical generating facilities that cannot change their allowable NOx emissions in their Facility Permit, staff is proposing a Regional NSR Holing Account in Rule 2002. Proposed changes in Rule 2005 would assure that the Regional NSR Holing Account would be used the for the purpose of complying with the NSR requirements.

Other Administrative Amendments

Besides the changes described in Rule 2002 and 2005 above, staff also proposes administrative amendments to Regulation XX to clarify the rule language and to ensure effective and consistent implementation of the RECLAIM program.

Rule 2002(b) - 5-Year Limitation on Amending Annual Emission Reports

Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx) specifies the procedures for quantifying RECLAIM allocations for facilities in the original (1994) RECLAIM universe, facilities electing to enter the program, and facilities included into the program because they experienced actual NOx or SOx emissions of four tons or more in a year. Allocations are quantified by multiplying throughput levels (*e.g.*, quantity of fuel consumed or of material processed) documented in peak year Annual Emission Reports (AERs), by emission factors specified in Rule 2002. However, if the emission factors used in preparing the peak year AER reports are lower than those in Rule 2002, then the lower factors are to be used for quantifying allocations.

Some facilities entering the RECLAIM program have sought to amend their past AERs, which dated as far back as 1989, in ways that increase the initial SOx and/or NOx allocations quantified for them pursuant to Rule 2002. The longer the time elapsed between the reporting period and submittal of the correction the more problematic the process of validating the proposed corrections and their supporting documentation becomes. In fact, such validation has been infeasible in some cases. Therefore, staff is proposing to add paragraph (b)(5) to Rule 2002 specifying that the Executive Officer will not consider any AER data submitted five years beyond the original due date when calculating a facility's allocation. This language would provide clarity to RECLAIM facilities and potential RECLAIM facilities regarding what AR submittals and/or revisions may be considered in determining their allocations, as well as relieve the costs, both financial and in terms of staff resources, associated with review and validation of AER submittals made long after the reporting periods for which they are submitted.

Rules 2011 and 2012 - Delayed RATA Tests due to Extenuating Circumstances

Rules 2011 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions and 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions set forth monitoring, reporting, and recordkeeping requirements for sources of SOx and NOx at RECLAIM facilities. The accompanying Appendices A to these rules, Rule 2011 – Protocol for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions and Rule 2012 – Protocol for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions, outline in greater detail the technical specifications required for monitoring, reporting, and recordkeeping for RECLAIM sources. Moreover, Attachment C, Subdivision B, Paragraph 2 of Appendix A of both these protocols, sets forth the timing and frequency of Semi-Annual Assessments in the form of Relative Accuracy Test Audits (RATAs) for RECLAIM Continuous Emission Monitoring Systems (CEMS). For instance, SOx and NOx equipment monitored by CEMS are required to perform RATAs on a semi-annual basis within six months of the end of the calendar quarter in which the CEMS last passed such a test. Such RATAs may be performed on an annual basis, provided that the relative accuracies of the SOx (NOx) pollutant concentration monitor, flow monitoring system, and the SOx (NOx) emission rate measurement system measured during the previous audit are 7.5% or less. These stringent testing requirements help ensure the accuracy of the CEMS in monitoring SOx and NOx emissions.

RATAs are conducted while the equipment is in operation. Equipment monitored by CEMS at some RECLAIM facilities, however, may experience extenuating circumstances that prevent them from conducting RATA tests in a timely manner. For instance, a major source may experience unforeseen equipment failure that renders it inoperable. Under such unforeseen events, the equipment cannot be made operational to conduct a RATA.

Additionally, facilities under contract with the California Independent System Operator (CalISO), as well as electrical generating facilities owned and operated by municipalities, have experienced difficulties in meeting RATA deadlines because their equipment operates based on current energy demand and may not operate long enough (or at all) to conduct a RATA in the quarter in which the RATA is due. In contrast, most facilities typically require their major sources to be continually operational, used on a regular basis, and able to conduct a timely RATA for their equipment. In the event that their equipment is not in operation, the facility has the option of seeking a variance or filing an application for non-operational status to avoid violating the RATA requirement since sources permitted as non-operational are not required to conduct RATAs. However, electrical generating facilities with equipment under contract with CalISO or owned and operated by municipalities often do not know when demand for electricity will result in generation equipment being required to operate until a day prior, creating scheduling difficulties in conducting RATAs and precluding the use of non-operational status. The inherent inconsistent operational nature of such equipment at electric generating facilities sometimes causes a need to postpone their RATAs.

Under current rule requirements, facilities having such extenuating circumstances seek variances for indeterminate amounts of time. The proposed amendments would, under specific conditions, allow RECLAIM Facility Permit Holders of equipment experiencing these extenuating circumstances to postpone RATAs. In the case of unforeseen equipment failure, Facility Permit Holders would have the option to postpone RATAs for this equipment to no more than 14 operating days after recommencing operation of the repaired equipment. Concerns were expressed that 14 operating days may not be sufficient in cases of sequential failures of the same equipment. However, the proposed 14 operating day RATA postponement for unforeseen equipment failure would apply separately for each unrelated, independent event. As such, if equipment operating under the 14 day RATA postponement provision should experience an unrelated failure prior to successfully completing a RATA, the 14 day clock would restart. On the other hand, if the same failure should recur in a similar situation, the 14 day clock would continue running and would not be reset. In the case of electrical generating facilities under contractual obligation with CalISO to have equipment available or owned and operated by municipalities that did not operate long enough to conduct a RATA during the quarter in which it is due, the semi-annual or annual assessment could be postponed to the next calendar quarter provided the follow criteria are met:

- The RATA was scheduled for the first 45 days of the calendar quarter in which it is due, but the equipment’s operating schedule prevents completion of the RATA; and

- A passing Cylinder Gas Audit is conducted during the calendar quarter in which the RATA is due.

Paragraph 2, Subdivision B, Attachment C, of Appendix A to both Rule 2011 and Rule 2012 establishes both the timeline and the frequency for Semi-Annual Assessments to be performed for equipment monitored by CEMS. The purpose of these stringent testing requirements is to ensure the accuracy of the CEMS in monitoring SOx and NOx emissions. These Semi-Annual Assessments obligate facility permit holders to conduct RATAs within six months of the end of the calendar quarter in which the CEMS was last tested. Alternatively, such RATAs may be performed on an annual basis, provided that the relative accuracies of the SOx (NOx) pollutant concentration monitor, flow monitoring system, and the SOx (NOx) emission rate measurement systems are all 7.5% or less. Furthermore, for CEMS on any stack or duct through which no emissions have passed in two or more successive quarters, the semi-annual assessments may be delayed until no later than 14 operating days after emissions pass through the stack/duct. Some

RECLAIM facilities that have had to disconnect their equipment due to failures and remove it off-site for repair have requested to have their RATA due dates extended. Other RECLAIM facilities, specifically electrical generating facilities that either have contractual agreements with CalISO to have their equipment available but not necessarily operating or are owned and operated by municipalities, have requested to delay their RATA testing until they have sufficient operating hours to conduct a RATA. Staff proposes to revise Attachment C. B.2. of Appendix A in both Rules 2011 and 2012 by adding subparagraphs (c) and (d), to allow RATA postponements due to these extenuating circumstances. For facilities that have major sources that are physically unable to operate to conduct a RATA, postponement of the RATA due date to within 14 unit operating days from the first re-firing of the major source is proposed to be allowed only if the following requirements are met:

- All fuel feed lines to the major source are disconnected and flanges are placed at both ends of the disconnected lines, and

- The fuel meter(s) for the disconnected fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site.

For any hour that fuel flow records are not available to verify no fuel flow, SOx (NOx) emissions would be required to be calculated using the maximum valid hourly emissions from the last 30 days of operation. Additionally, prior to equipment restart the Facility Permit Holder would be required to:

- provide written notification to the District no later than 72 hours prior to starting up the major source;

- start the CEMS no later than 24 hours prior to the start-up of the major source; and

- conduct and pass a Cylinder Gas Analysis (CGA) prior to the start-up of the major source.

CEMS emissions data after the re-start of operations would only be considered valid if the Facility Permit Holder passes the CGA test. Otherwise, for a non-passing CGA, the CEMS data would be considered invalid until the semi-annual or annual assessment is performed and passed. For such invalid CEMS emissions data, SOx (NOx) emissions would be calculated using the maximum valid hourly emissions from the last 30 days of operation, commencing with the hour of startup and continuing through the hour prior to performing and passing the semi-annual or annual assessment.

For electrical generating facilities either having contractual agreements with CalISO to have their major source available but not necessarily operating, yet not having sufficient hours to conduct

RATA testing or owned and operated by a municipality, amended rule language is being proposed to allow the postponement of the semi-annual or annual assessment to the next calendar quarter, provided that the facility demonstrates:

- the semi-annual or annual assessment was scheduled to be performed during the first 45 days of the calendar quarter in which the assessment is due but the assessment was not completed due to lack of adequate operational time, and

- a Cylinder Gas Audit (CGA) is conducted and passed within the calendar quarter when the assessment is due.

Rules 2011 and 2012 - Typographical Edits

The staff proposal would, if adopted, also make the following typographical clarifications and corrections:

- Under Rules 2011 and 2012 Appendix A, Attachment C B.2.b the word "unit" would be added to offer clarity regarding the time period for RATAs that are conducted on equipment for which no emissions have passed through any stack or duct in two or more successive quarters;

- The rule language "Proposed" and "Draft" found in Rule 2011 Appendix A, Attachment C B.2.e., which inadvertently had been left in the previous amended rules, would now be deleted;

- Rule language found in subparagraph (e) of Rule 2012 Appendix A, Attachment C B.2, referencing "Chapter 2, Subdivision B, Paragraph 10, Chapter 2, Subdivision B, Paragraph 11, and Chapter 2, Subdivision B, Paragraph 12" would be replaced with "Chapter 2, Subdivision B, Paragraphs 10, 11, 12, and 18", to clarify relative accuracy requirements for fuel flow measuring devices; and

- Rule language found in subparagraph (e) of Rule 2011 Appendix A, Attachment C B.2 referencing "Chapter 2, Subdivision B, Paragraphs 10, 11, and 12…" would be replaced with "Chapter 2, Subdivision B, Paragraphs 10, 11, 12, and 13…" to clarify the relative accuracy requirements for analyzers.

Appendix Y – RTC Holdings as of September 22, 2015

ID	Name	Current IYB RTC Holding (tons)	Current IYB RTC Holding (tons per day)
136	PRESS FORGE CO	3.6	0.01
346	FRITO-LAY, INC.	15.2	0.04
550	LA CO., INTERNAL SERVICE DEPT	17.6	0.05
710	TEXACO EXPLORATION & PRODUCTION INC.	2.0	0.01
1073	BORAL ROOFING LLC	24.2	0.07
1744	KIRKHILL - TA COMPANY	1.2	0.00
2083	SUPERIOR INDUSTRIES INTERNATIONAL INC	0.1	0.00
2418	FRUIT GROWERS SUPPLY CO	1.9	0.01
2825	MCP FOODS INC	2.2	0.01
2912	HOLLIDAY ROCK CO INC	1.6	0.00
2946	PACIFIC FORGE INC	2.5	0.01
3029	MATCHMASTER DYEING & FINISHING INC	3.8	0.01
3417	AIR PROD & CHEM INC	15.1	0.04
3585	R. R. DONNELLEY & SONS CO, LA MFG DIV	4.2	0.01
3704	ALL AMERICAN ASPHALT, UNIT NO.01	14.5	0.04
3721	DART CONTAINER CORP OF CALIFORNIA	3.5	0.01
3968	TABC, INC	28.0	0.08
4242	SAN DIEGO GAS & ELECTRIC	48.3	0.13
4477	SO CAL EDISON CO	68.7	0.19
5973	SO CAL GAS CO	30.3	0.08
5998	ALL AMERICAN ASPHALT	1.4	0.00
7411	DAVIS WIRE CORP	2.4	0.01
7416	PRAXAIR INC	8.0	0.02
7427	OWENS-BROCKWAY GLASS CONTAINER INC	50.0	0.14
8439	EXXON MOBIL CORP	3.8	0.01
8547	QUEMETCO INC	24.4	0.07
8582	SO CAL GAS CO/PLAYA DEL REY STORAGE FACI	27.2	0.07
9053	VEOLIA ENERGY LOS ANGELES, INC	7.2	0.02
9755	UNITED AIRLINES INC	0.8	0.00
10141	ANGELICA TEXTILE SERVICES	2.0	0.01
11034	VEOLIA ENERGY LOS ANGELES, INC	8.2	0.02
11119	THE GAS CO./ SEMPRA ENERGY	0.9	0.00
11142	KEYSOR-CENTURY CORP	1.7	0.00
11435	PQ CORPORATION	24.9	0.07
11716	FONTANA PAPER MILLS INC	4.7	0.01
11887	NASA JET PROPULSION LAB	21.4	0.06
12155	ARMSTRONG WORLD INDUSTRIES INC	1.2	0.00
12372	MISSION CLAY PRODUCTS	3.7	0.01
12428	NEW NGC, INC.	15.0	0.04
12912	LIBBEY GLASS INC	0.0	0.00
13179	CRESCENT CRANES INC	0.2	0.00
14049	MARUCHAN INC	1.5	0.00
14092	CPC INTERNATIONAL INC, BEST FOODS DIV	1.3	0.00
14495	VISTA METALS CORPORATION	15.4	0.04
14502	CITY OF VERNON, VERNON GAS & ELECTRIC	2.1	0.01
14736	THE BOEING COMPANY	1.4	0.00

ID	Name	Current IYB RTC Holding (tons)	Current IYB RTC Holding (tons per day)
14871	SONOCO PRODUCTS CO	2.4	0.01
14926	SEMPRA ENERGY (THE GAS CO)	2.9	0.01
14944	CENTRAL WIRE, INC.	3.5	0.01
15381	CHEVRON USA INC	1.5	0.00
15504	SCHLOSSER FORGE COMPANY	10.9	0.03
16338	KAISER ALUMINUM FABRICATED PRODUCTS, LLC	4.8	0.01
16352	SO CAL EDISON CO	7.0	0.02
16639	SHULTZ STEEL CO	18.6	0.05
16642	ANHEUSER-BUSCH LLC., (LA BREWERY)	21.5	0.06
16660	THE BOEING COMPANY	2.2	0.01
16978	CLOUGHERTY PACKING LLC/HORMEL FOODS CORP	4.5	0.01
17344	EXXONMOBIL OIL CORP	1.8	0.00
17623	LOS ANGELES ATHLETIC CLUB	0.8	0.00
17953	PACIFIC CLAY PRODUCTS INC	42.6	0.12
17956	WESTERN METAL DECORATING CO	0.7	0.00
18294	NORTHROP GRUMMAN SYSTEMS CORP	16.9	0.05
18455	ROYALTY CARPET MILLS INC	2.7	0.01
18931	TAMCO	73.7	0.20
19167	R J. NOBLE COMPANY	7.1	0.02
19390	SULLY-MILLER CONTRACTING CO.	3.0	0.01
19989	PARKER HANNIFIN AEROSPACE CORP	0.1	0.00
20203	RECYCLE TO CONSERVE INC.	1.4	0.00
20543	REDCO II	0.9	0.00
20604	RALPHS GROCERY CO	2.9	0.01
21598	ANGELICA TEXTILE SERVICES	1.8	0.00
21887	KIMBERLY-CLARK WORLDWIDE INC.-FULT. MILL	8.7	0.02
22603	EXXONMOBIL PRODUCTION COMPANY	3.7	0.01
22607	CALIFORNIA DAIRIES, INC	4.1	0.01
22911	CARLTON FORGE WORKS	3.8	0.01
23752	AEROCRAFT HEAT TREATING CO INC	3.6	0.01
25058	EXXONMOBIL OIL CORP	1.8	0.00
25638	BURBANK CITY, BURBANK WATER & POWER	36.8	0.10
35302	OWENS CORNING ROOFING AND ASPHALT, LLC	4.3	0.01
36909	LA CITY, DEPARTMENT OF AIRPORTS	4.5	0.01
37603	SGL TECHNIC INC, POLYCARBON DIVISION	2.2	0.01
38440	COOPER & BRAIN - BREA	0.0	0.00
38872	MARS PETCARE U.S., INC.	4.1	0.01
40034	BENTLEY PRINCE STREET INC	4.2	0.01
40483	NELCO PROD. INC	1.4	0.00
42079	ROD'S FOOD PRODUCTS	0.4	0.00
42630	PRAXAIR INC	2.8	0.01
42775	WEST NEWPORT OIL CO	2.0	0.01
43201	SNOW SUMMIT INC	68.5	0.19
43436	TST, INC.	18.9	0.05
45746	PABCO BLDG PRODUCTS LLC,PABCO PAPER, DBA	12.7	0.03
46268	CALIFORNIA STEEL INDUSTRIES INC	160.5	0.44
47781	OLS ENERGY-CHINO	17.4	0.05
50098	D&D DISPOSAL INC,WEST COAST RENDERING CO	1.5	0.00

ID	Name	Current IYB RTC Holding (tons)	Current IYB RTC Holding (tons per day)
14871	SONOCO PRODUCTS CO	2.4	0.01
14926	SEMPRA ENERGY (THE GAS CO)	2.9	0.01
14944	CENTRAL WIRE, INC.	3.5	0.01
51620	WHEELABRATOR NORWALK ENERGY CO INC	31.0	0.09
52517	REXAM BEVERAGE CAN COMPANY	11.1	0.03
53729	TREND OFFSET PRINTING SERVICES, INC	2.2	0.01
54402	SIERRA ALUMINUM COMPANY	7.2	0.02
56940	CITY OF ANAHEIM/COMB TURBINE GEN STATION	4.8	0.01
58622	LOS ANGELES COLD STORAGE CO	0.2	0.00
59618	PACIFIC CONTINENTAL TEXTILES, INC.	1.9	0.01
60531	PACIFIC FABRIC FINISHING	1.1	0.00
61722	RICOH ELECTRONICS INC	1.7	0.00
61962	LA CITY, HARBOR DEPT	3.2	0.01
62548	THE NEWARK GROUP, INC.	4.6	0.01
63180	DARLING INTERNATIONAL INC	7.5	0.02
68042	CORONA ENERGY PARTNERS, LTD	12.7	0.03
68118	TIDELANDS OIL PRODUCTION COMPANY ETAL	2.9	0.01
73022	US AIRWAYS INC	0.7	0.00
74424	ANGELICA TEXTILE SERVICES	1.3	0.00
83102	LIGHT METALS INC	7.0	0.02
84223	NEWELLRUBBERMAID INC	0.8	0.00
85943	SIERRA ALUMINUM COMPANY	4.3	0.01
89248	OLD COUNTRY MILLWORK INC	1.4	0.00
94872	METAL CONTAINER CORP	12.1	0.03
94930	CARGILL INC	0.9	0.00
95212	FABRICA	4.7	0.01
96587	TEXOLLINI INC	0.4	0.00
97081	THE TERMO COMPANY	0.9	0.00
99588	DOMTAR GYPSUM INC	7.5	0.02
101337	NATIONAL OFFSETS	0.3	0.00
101656	AIR PRODUCTS AND CHEMICALS, INC.		
101977	SIGNAL HILL PETROLEUM INC	4.5	0.01
105277	SULLY MILLER CONTRACTING CO	2.6	0.01
105903	PRIME WHEEL	0.7	0.00
107653	CALMAT CO	1.3	0.00
107654	CALMAT CO	2.7	0.01
107655	CALMAT CO	9.5	0.03
107656	CALMAT CO	2.9	0.01
113160	HILTON COSTA MESA	1.8	0.00
114264	ALL AMERICAN ASPHALT	3.3	0.01
115172	RAYTHEON COMPANY	2.1	0.01
115241	THE BOEING COMPANY	4.8	0.01
115277	LAFAYETTE TEXTILE IND LLC	0.0	0.00
115314	LONG BEACH GENERATION, LLC	43.2	0.12
115315	NRG CALIFORNIA SOUTH LP, ETIWANDA GEN ST	132.1	0.36
115389	AES HUNTINGTON BEACH, LLC	89.9	0.25
115394	AES ALAMITOS, LLC	273.0	0.75
115449	PLAYA PHASE I COMMERCIAL LAND, LLC	0.0	0.00
115536	AES REDONDO BEACH, LLC	147.0	0.40
115563	NCI GROUP INC., DBA, METAL COATERS OF CA	1.0	0.00
115663	EL SEGUNDO POWER, LLC	247.8	0.68
117140	AOC, LLC	2.0	0.01

ID	Name	Current IYB RTC Holding (tons)	Current IYB RTC Holding (tons per day)
14871	SONOCO PRODUCTS CO	2.4	0.01
14926	SEMPRA ENERGY (THE GAS CO)	2.9	0.01
14944	CENTRAL WIRE, INC.	3.5	0.01
51620	WHEELABRATOR NORWALK ENERGY CO INC	31.0	0.09
52517	REXAM BEVERAGE CAN COMPANY	11.1	0.03
53729	TREND OFFSET PRINTING SERVICES, INC	2.2	0.01
54402	SIERRA ALUMINUM COMPANY	7.2	0.02
56940	CITY OF ANAHEIM/COMB TURBINE GEN STATION	4.8	0.01
58622	LOS ANGELES COLD STORAGE CO	0.2	0.00
59618	PACIFIC CONTINENTAL TEXTILES, INC.	1.9	0.01
60531	PACIFIC FABRIC FINISHING	1.1	0.00
61722	RICOH ELECTRONICS INC	1.7	0.00
117227	SHCI SM BCH HOTEL LLC, LOEWS SM BCH HOTE	1.5	0.00
117290	B BRAUN MEDICAL, INC	7.8	0.02
118406	CARSON COGENERATION COMPANY		
118618	UNI-PRESIDENT (U.S.A.) INC	1.1	0.00
119134	ITW CIP CALIFORNIA	0.0	0.00
119596	SNAK KING CORPORATION	4.2	0.01
123774	HERAEUS PRECIOUS METALS NO. AMERICA, LLC	4.7	0.01
124619	ARDAGH METAL PACKAGING USA INC.	0.7	0.00
124723	GREKA OIL & GAS, INC	0.5	0.00
124808	INEOS POLYPROPYLENE LLC	2.0	0.01
124838	EXIDE TECHNOLOGIES		
125579	DIRECTV	0.0	0.00
126498	STEELSCAPE, INC	14.2	0.04
127299	WILDFLOWER ENERGY LP/INDIGO GEN., LLC	25.2	0.07
128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA	49.0	0.13
129810	CITY OF RIVERSIDE PUBLIC UTILITIES DEPT	10.1	0.03
129816	INLAND EMPIRE ENERGY CENTER, LLC		
130211	PAPER-PAK INDUSTRIES	6.3	0.02
131850	SHAW DIVERSIFIED SERVICES INC	7.6	0.02
132068	BIMBO BAKERIES USA INC	3.2	0.01
133405	BODYCOTE THERMAL PROCESSING	2.3	0.01
137471	GRIFOLS BIOLOGICALS INC	6.0	0.02
137508	TONOGA INC, TACONIC DBA	1.5	0.00
138568	CALIFORNIA DROP FORGE, INC	0.9	0.00
139796	CITY OF RIVERSIDE PUBLIC UTILITIES DEPT	14.7	0.04
141555	CASTAIC CLAY PRODUCTS, LLC	14.0	0.04
142267	FS PRECISION TECH LLC	1.2	0.00
142536	DRS SENSORS & TARGETING SYSTEMS, INC	0.1	0.00
143738	DCOR LLC	1.1	0.00
143739	DCOR LLC	0.2	0.00
143740	DCOR LLC	8.8	0.02
143741	DCOR LLC	3.5	0.01
144455	LIFOAM INDUSTRIES, LLC	0.7	0.00
146536	WALNUT CREEK ENERGY, LLC	57.5	0.16
148340	THE BOEING CO. COMMERCIAL AVIATION SRVCS	6.8	0.02
148896	VINTAGE PRODUCTION CALIFORNIA LLC	1.2	0.00
148897	VINTAGE PRODUCTION CALIFORNIA LLC	0.8	0.00
148925	CHERRY AEROSPACE	1.8	0.00
149491	BOEING REALTY CORP		

ID	Name	Current IYB RTC Holding (tons)	Current IYB RTC Holding (tons per day)
151394	LINN OPERATING INC	0.1	0.00
151415	LINN WESTERN OPERATING, INC	0.0	0.00
151532	LINN OPERATING, INC	7.8	0.02
151594	OXY USA, INC	2.8	0.01
151798	TESORO REFINING AND MARKETING CO, LLC	49.6	0.14
151899	VINTAGE PRODUCTION CALIFORNIA LLC	1.9	0.01
152054	LINN WESTERN OPERATING INC	0.0	0.00
152501	PRECISION SPECIALTY METALS, INC.	1.8	0.00
152707	CPV SENTINEL LLC	120.5	0.33
153033	GEORGIA-PACIFIC CORRUGATED LLC	0.6	0.00
153199	THE KROGER CO/RALPHS GROCERY CO	1.8	0.01
153992	CANYON POWER PLANT	42.0	0.12
155221	SAVE THE QUEEN LLC (DBA QUEEN MARY)	1.1	0.00
155474	BICENT (CALIFORNIA) MALBURG LLC	26.9	0.07
155877	MILLERCOORS, LLC	21.9	0.06
156722	AMERICAN APPAREL KNIT AND DYE	3.7	0.01
156741	HARBOR COGENERATION CO, LLC	20.9	0.06
157359	HENKEL ELECTRONIC MATERIALS, LLC	0.9	0.00
157363	INTERNATIONAL PAPER CO	1.5	0.00
158300	CITY OF ONTARIO	2.8	0.01
160437	SOUTHERN CALIFORNIA EDISON	144.8	0.40
161300	SAPA EXTRUDER, INC	5.7	0.02
164204	CITY OF RIVERSIDE, PUBLIC UTILITIES DEPT	9.2	0.03
165192	TRIUMPH AEROSTRUCTURES, LLC	2.8	0.01
166073	BETA OFFSHORE		
168088	PCCR USA	2.4	0.01
169514	TITAN TERMINAL AND TRANSPORT INC	0.0	0.00
169678	ITT CANNON, LLC	0.3	0.00
169754	SO CAL HOLDING, LLC	104.4	0.29
171107	PHILLIPS 66 CO/LA REFINERY WILMINGTON PL	584.4	1.60
171109	PHILLIPS 66 COMPANY/LOS ANGELES REFINERY	139.7	0.38
172005	NEW- INDY ONTARIO, LLC	65.2	0.18
172077	CITY OF COLTON	16.4	0.04
173904	LAPEYRE INDUSTRIAL SANDS, INC	4.3	0.01
174406	ARLON GRAPHICS LLC	1.3	0.00
174544	BREITBURN OPERATING LP	2.4	0.01
174591	TESORO REF & MKTG CO LLC,CALCINER	133.7	0.37
174655	TESORO REFINING & MARKETING CO, LLC	839.0	2.30
175124	AEROJET ROCKETDYNE OF DE, INC.	1.6	0.00
175154	FREEPORT-MCMORAN OIL & GAS	2.5	0.01
175191	FREEPORT-MCMORAN OIL & GAS	9.4	0.03
176708	ALTAGAS POMONA ENERGY INC.	15.5	0.04
178639	ECO SERVICES OPERATIONS LLC	26.0	0.07
179137	QG PRINTING II CORP	0.6	0.00
179957	CA LOS ANGELES TIMES SQUARE LLC	2.6	0.01
180367	LINN OPERATING INC	39.9	0.11
180410	REICHHOLD LLC 2	1.4	0.00
700050	KEN BARKER	1.5	0.00
700084	SHELL NORTH AMERICA (US), L.P.	2.5	0.01
700126	GENERAL ELECTRIC COMPANY	113.3	0.31
700144	OLDUVAI GORGE, LLC	27.8	0.08
700161	KOCH SUPPLY & TRADING, LP	85.9	0.24

ID	Name	Current IYB RTC Holding (tons)	Current IYB RTC Holding (tons per day)
700170	ABATEMENT CAPITAL LLC	20.2	0.06
700177	GREY EPOCH LLC	2.0	0.01
800003	HONEYWELL INTERNATIONAL INC	2.7	0.01
800016	BAKER COMMODITIES INC	9.3	0.03
800026	ULTRAMAR INC	561.4	1.54
800030	CHEVRON PRODUCTS CO.	1,289.1	3.53
800037	DEMENNO/KERDOON	4.6	0.01
800038	THE BOEING COMPANY - C17 PROGRAM	13.7	0.04
800042	ECO PETR INC (EIS USE ONLY)	0.6	0.00
800066	HITCO CARBON COMPOSITES INC	8.7	0.02
800067	THE BOEING COMPANY	2.2	0.01
800074	LA CITY, DWP HAYNES GENERATING STATION	189.5	0.52
800075	LA CITY, DWP SCATTERGOOD GENERATING STN	179.1	0.49
800080	LUNDAY-THAGARD COMPANY	18.1	0.05
800088	3M COMPANY	14.2	0.04
800089	EXXONMOBIL OIL CORPORATION	900.9	2.47
800094	EXXONMOBIL OIL CORPORATION	2.0	0.01
800099	NORRIS IND (EIS USE)	0.3	0.00
800110	THE BOEING COMPANY	1.3	0.00
800113	ROHR, INC.	8.6	0.02
800127	SO CAL GAS CO	41.6	0.11
800128	SO CAL GAS CO	179.7	0.49
800129	SFPP, L.P.	6.3	0.02
800149	US BORAX INC	4.2	0.01
800150	US GOVT, AF DEPT, MARCH AIR RESERVE BASE	7.4	0.02
800153	US GOVT, NAVY DEPT LB SHIPYARD	25.7	0.07
800168	PASADENA CITY, DWP	29.5	0.08
800170	LA CITY, DWP HARBOR GENERATING STATION	20.1	0.06
800181	CALIFORNIA PORTLAND CEMENT CO	1.5	0.00
800182	RIVERSIDE CEMENT CO	1.1	0.00
800183	PARAMOUNT PETR CORP	68.6	0.19
800189	DISNEYLAND RESORT	53.0	0.15
800193	LA CITY, DWP VALLEY GENERATING STATION	40.6	0.11
800196	AMERICAN AIRLINES INC	2.9	0.01
800205	BANK OF AMERICA NT & SA, BREA CENTER	1.6	0.00
800210	CONEXANT SYSTEMS INC	1.6	0.00
800253	UNION CARBIDE CORP	0.1	0.00
800264	EDGINGTON OIL COMPANY	17.0	0.05
800310	TA INDUSTRIES INC	0.5	0.00
800325	TIDELANDS OIL PRODUCTION CO	8.7	0.02
800330	THUMS LONG BEACH	2.6	0.01
800335	LA CITY, DEPT OF AIRPORTS	16.8	0.05
800337	CHEVRON U.S.A., INC (NSR USE)	8.8	0.02
800338	SPECIALTY PAPER MILLS INC	2.4	0.01
800342	ARTESIA KNITS INC	1.6	0.00
800344	CALIFORNIA AIR NATIONAL GUARD, MARCH AFB	0.7	0.00

ID	Name	Current IYB RTC Holding (tons)	Current IYB RTC Holding (tons per day)
800371	RAYTHEON SYSTEMS COMPANY - FULLERTON OPS	2.3	0.01
800372	EQUILON ENTER. LLC, SHELL OIL PROD. US	16.4	0.04
800373	LAKELAND DEVELOPMENT COMPANY	0.0	0.00
800393	VALERO WILMINGTON ASPHALT PLANT	5.3	0.01
800408	NORTHROP GRUMMAN SYSTEMS	6.8	0.02
800409	NORTHROP GRUMMAN SYSTEMS CORPORATION	12.8	0.03
800416	PLAINS WEST COAST TERMINALS LLC	0.4	0.00
800417	PLAINS WEST COAST TERMINALS LLC	2.5	0.01
800419	PLAINS WEST COAST TERMINALS LLC	0.3	0.00
800420	PLAINS WEST COAST TERMINALS LLC	1.8	0.00
800436	TESORO REFINING AND MARKETING CO, LLC	667.9	1.83
	TOTAL (TONS PER DAY)		**26.5**

Appendix Z – Comment Letters Received and Responses to Comments

The Public Workshop for RECLAIM was held on July 22, 2015. Comment letters received on and after that date are responded to below. Over the three year rule development process, many other letters, emails, and verbal comments have been received. These comments helped the rule proposal evolve, and staff appreciates all the stakeholder input.

More recent comment letters have been numbered and individual comments within each letter have been bracketed and numbered. Following each comment letter is staff's responses to the individual comments.

Comment Letter #1	WSPA's letter dated August 21, 2015, Phillips66 letter dated August 21, 2015

In addition to the letters above, the following comment letters were received from July 22 to August 10, 2015. The comments from these letters and staff responses are summarized in this Appendix, followed by an attachment that includes these comment letters.

Comment Letter #2	Norton Engineering letter dated August 10, 2015
Comment Letter #3	Norton Engineering letter dated September 4, 2015
Comment Letter #4	Industry Coalition letter dated August 21, 2015
Comment Letter #5	Latham & Watkins letter dated August 20, 2015
Comment Letter #6	Yorke Engineering, LLC letter dated August 21, 2015
Comment Letter #7	Charles F. Timms, Jr. August 21, 2015
Comment Letter #8	SCEC letter dated August 26, 2015
Comment Letter #9	Eco Services letter dated August 28, 2015
Comment Letter #10	Charles F. Timms, Jr. dated September 17, 2015
Comment Letter #11	Southern California Edison (no date)
Comment Letter #12	Inland Empire Energy Center – GE Capital dated September 22, 2015
Comment Letter #13	Earth Justice dated July 8, 2014
Comment Letter #14	Arnie Smith email dated August 11, 2015
Comment Letter #15	Karl Lany email dated August 20, 2015
Comment Letter #16	George Piantka email dated August 14, 2015
Comment Letter #17	Chuck Casey email dated September 24, 2015

Comment Letter #1 – WSPA's Letter and Phillips 66's Letter Dated August 21, 2015

WSPA

Western States Petroleum Association
Credible Solutions • Responsive Service • Since 1907

Sue Gornick
Senior Coordinator, Southern California Region

VIA ELECTRONIC MAIL

August 21, 2015

Dr. Philip Fine
Deputy Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

SUBJECT: WSPA COMMENTS ON PRELIMINARY DRAFT STAFF REPORT (PDSR) FOR NOX RECLAIM AMENDMENTS DATED JULY 21, 2015

Dear Dr. Fine:

1-1

The Western States Petroleum Association (WSPA) is a non-profit trade association representing twenty-five companies that explore for, produce, refine, transport and market petroleum, petroleum products, natural gas and other energy supplies in California, Arizona, Nevada, Oregon, and Washington. WSPA-member companies operate petroleum refineries and other facilities in the South Coast Air Basin that are within the purview of the Regional Clean Air Incentives Market (RECLAIM) program.

WSPA and the Industry RECLAIM Coalition (of which we are a member) have submitted several comment letters during this rulemaking process to request changes to the District Staff's proposal that we believe are necessary to preserve a healthy and successful RECLAIM program for all RECLAIM participants, as well as to satisfy the 2012 AQMP commitments to the State Implementation Plan (SIP) and USEPA. We have not yet received written responses to these comments. Nevertheless, we appreciate the opportunity to provide this letter to reiterate our previous concerns, and to discuss new issues arising from the PDSR.

Below are the highlights of our major concerns. More detailed comments are included in Attachment 1, attached hereto and incorporated herein by reference.

I. Shave Methodology and Arbitrary Removal of Unused RECLAIM Trading Credits (RTCs)

The District's Remaining Emissions method for calculation of RTC reductions conflicts with the CMB-01 Phase 1 and Phase 2 Control Measures as approved under the 2012 AQMP. The District's Remaining Emissions method would remove nearly all Unused RTCs from the RECLAIM market even though CMB-01 Phase 1 had explicitly considered and rejected such a reduction, instead determining that a 2 tpd reduction of Unused RTCs was more appropriate.[1] Additionally, the Incremental BARCT method proposed by the Industry RECLAIM Coalition is more consistent with Control Measure CMB-01 Phase 2 as approved under the 2012 AQMP because this method removes only those RTCs directly attributable to technology advancement (i.e., BARCT).[2]

Further, the proposed Compliance Margin of 10% may be inadequate to meet the market's historical need for Unused RTCs. Unused RTCs may be needed for several reasons, including
1-2 facility-level compliance margins, which vary depending on facility size and/or risk tolerance; RTC holding requirements imposed under Rule 2005; and market liquidity, to name a few. These Unused RTCs have historically averaged in the 15-30% range (approximately 5 to 9 tpd), with the sole exception being the RTC market crisis during the 2000 compliance year. The AQMD Staff's proposal, which includes only a 10% compliance margin, appears to be inadequate for satisfying this market requirement. Hence, WSPA recommends that Staff adopt the Incremental BARCT method as their preferred proposal.

While the proposed, limited RTC adjustment account may help certain Power Sector facilities subject to Rule 2005 New Source Review (NSR) RTC holding limit requirements, it does not resolve the holding requirements applicable to many current and future non-power facilities. It is recommended that any RTC adjustment account be accessible to all RECLAIM participants subject to the Rule 2005 NSR RTC holding requirement. WSPA also recommends that Staff provide technical justification to support the quantity of RTCs set aside to fund any such adjustment account. Finally, WSPA recommends that USEPA approval of the NSR set aside concept be obtained in writing prior to adoption of the rule amendment.

II. Shave Application and Implementation Schedule

Any NOx RECLAIM shave should be applied in an equally distributed "across-the-board" manner consistent with RECLAIM founding principles[3] and the precedent set under the 2005 NOx RECLAIM shave. In addition, the proposed schedule should be consistent with the 2012 AQMP commitment to the State Implementation Plan (SIP) which was 2 tpd in the first year; anything larger may not allow sufficient time for industry to implement emission control projects necessitated by the rulemaking.[4] Since RECLAIM is tied to BARCT (as discussed in more detail below), the lack of sufficient lead time means that the proposed shave goes beyond

---

[1] SCAQMD, 2012 AQMP. Page 4-9 states: "The control measure will seek further reductions of 2 tpd of NOx allocations if triggered." Appendix A, page IV-A-13 presents rationale for that conclusion.
[2] SCAQMD, 2012 AQMP. Page 4-26 states: "This phase of control is to implement periodic BARCT evaluation as required under the state law." Appendix A, page IV-A-60 presents more detailed discussion for the measure.
[3] SCAQMD, Staff Report for Proposed Amended Regulation XX – RECLAIM, January 2005, Executive Summary.
[4] WSPA-SCAQMD letter, July 14, 2015.

BARCT and that RECLAIM will not achieve equivalent or greater reductions than BARCT at equivalent or lesser cost. Therefore, the shave implementation schedule should be "back-loaded"
1-3 to accommodate a longer, more realistic project implementation period with at least 2 of the proposed 4 tpd (currently being proposed for 2016) being moved to 2019 or later. We are not recommending additional annual increments at this time, since the final shave amount has not been finalized.

III. Useful Life of Control Equipment

The proposed Useful Life of 25 years is inappropriate because AQMD rulemaking is far more frequent, with the prior major NOx RECLAIM rulemaking occurring only 10 years ago. Use of a 25 year assumption makes the rule costs appear lower than they actually are by diluting the
1-4 significant capital costs of required projects over a much longer time table than is likely to occur. The Staff analysis should be revised to reflect the 10-year Useful Life assumption, which is more consistent with recent SCAQMD rulemaking schedules and is also consistent with the Useful Life assumption typically used by CARB and other major Air Districts.

IV. BARCT Analysis

There is a statutory requirement that RECLAIM achieve equivalent or greater emission reductions than command and control at equivalent or lesser cost.

Command and Control Regulation Would Require BARCT of the Refining Sources Subject to RECLAIM: The District is required to adopt rules and regulations implementing the AQMP.[5] Among other things, these rules and regulations must require BARCT for existing sources.[6] In rulemaking addressing existing sources outside of RECLAIM, SCAQMD is mandated to require BARCT. Because of the mandate to require BARCT on all existing sources, it is fair to say that current command and control regulations and future measures adopted as part of the plan would at least be equivalent to BARCT. In the absence of a market-based mechanism (cap-and-trade program) such as RECLAIM, SCAQMD would adopt a rule requiring source-specific BARCT for each of the sources covered under RECLAIM.

1-5

The Proposed Shave Appears to Include an Additional 5.21 Tons per Day Beyond BARCT: The proposal set forth by the District indicates that the proposed BARCT would result in a reduction of 8.79 tpd of NOx from 2011 emissions at 2000/2005 BARCT. As described above, RECLAIM must achieve emission reductions equivalent to or greater than traditional command and control, or BARCT. Thus, a NOx shave equivalent to BARCT (which the District proposes at 8.79 tpd) would be the level for comparison with the Health and Safety Code provision stating that equivalent or greater reductions would be achieved at "equivalent or less cost compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment." Yet, SCAQMD does not seek merely its determined BARCT equivalency level of 8.79 tpd; it seeks 14 tpd of NOx reductions and has not demonstrated that such reductions will be achieved at equivalent or lower cost than

[5] Health & Saf. Code § 40460.
[6] Health & Saf. Code § 40440.

BARCT. The additional 5.21 tpd reduction goes above and beyond BARCT. Such a severe reduction is not essential to compliance with the statute.

SCAQMD Needs to Demonstrate that Achieving This Additional 5.21 Tons per Day Would Be Less Costly than Achieving BARCT on a Source-by-Source Basis in the District: The Health and Safety Code requires RECLAIM to achieve at least equivalent reductions as traditional command and control at an equivalent or lesser cost.[7] While the draft staff report does provide a cost accounting for BARCT, that accounting (which we believe to be understated) only covers 8.79 tons of the 14 ton per day shave. The draft staff report does not even mention, let alone provide detailed discussion of, the costs associated with the additional 5.21 tons per day being required by the proposed rule. Because the Legislature has required RECLAIM to impose costs less than or equal to command and control regulation (i.e., BARCT), and BARCT only makes up a portion of the proposed shave, the remaining reductions which are in excess of BARCT will cost more than BARCT. The costs related solely to BARCT are substantial with refinery costs over $900 million.[8] Costs associated with the additional 5.21 tpd reduction will only increase that figure in a substantial manner. The District must include the cost figures for the additional shave amount and justify imposing these reductions under the statutory standard of achieving command and control levels at equivalent or lower costs. It is simply not reasonable to exclude such a relevant factor from consideration.

V. NEC Study

1-6

The BARCT analysis for Refinery Sector categories should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review.[9] NEC is a third-party expert hired to confirm the Staff's technical analysis in support of this rulemaking. Following the issuance of the PDSR, however, NEC responded to SCAQMD in an August 10, 2015 letter (see Attachment 2) to "clarify the most glaring misstatements/misunderstandings of the information [NEC] provided to the District." By selectively dismissing the third-party expert's findings, without resolution of the technical issues in dispute, Staff has compromised the process and the results of that process. It is unacceptable to arbitrarily reduce the overall shave by 0.85 tpd to resolve the differences in technical assumptions. For example, if the Staff disregards the conclusion from the NEC's third-party expert report, nearly 40 operating units would be impacted by this analysis error.[10] Furthermore, any adjustment that may be justified on a technical basis should be applied to the sector where the actual BARCT reduction occurs and not to the total shave reduction (i.e., Staff's proposed adjustment of 0.85 tpd should be applied to the Refinery Sector's BARCT reduction).

While WSPA understands that BARCT should represent a level of performance that is technically feasible and cost-effective for most units on a retrofit basis in a given source category, the District's assumptions regarding the feasibility of achieving the BARCT levels are

[7] Health & Saf. Code § 39616(c)(7).
[8] SCAQMD, *Preliminary Draft Staff Report, Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM* (Draft NOx RECLAIM Staff Report), p. 23. (July 21, 2015)
[9] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM – BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.
[10] SCAQMD, Preliminary Analysis – Refinery Boilers/Heaters, July 2014 (posted on AQMD website October 2014).

not supported by evidence that the units in question can achieve 2 ppm NOx. In fact, the data provided by Staff (Appendix B of the PDSR) indicates that only 4 of the 76 installed SCRs in the boiler and heater category are currently performing below 2 ppm. This alone suggests that the proposed BARCT is not representative. Even more, in a confidential WSPA refinery survey,[11] conducted by a third party contractor, only 2 of the 4 are retrofits. This does not represent the necessary proportion of the units in this source category.

The draft staff report proposes 2015 BARCT levels of 2 ppmv of NOx for FCCUs, refinery heaters and boilers greater than 40 mmbtu/hr, gas turbines, and sulfur recovery unit tail gas
1-7 incinerators. While the District justifies these levels based on an assumption that all refinery equipment can reach such levels, the draft staff report says otherwise. With respect to refinery heaters and boilers, very few of the existing refinery heaters and boilers already equipped with SCR are able to meet 2 ppmv of NOx. In fact, as stated in the draft staff report, of the 212 refinery boilers and heaters classified as major and large NOx sources, 14 heaters using refinery fuel gas have achieved 1.6-3.5 ppmv NOx, two boilers using natural gas have achieved 2-5 ppmv NOx, and a crude heater using refinery fuel gas achieved 3-8 ppmv NOx. Apart from some unknown percentage of the 14 process heaters, none of these sources already employing the control technology on which the BARCT level is based (SCR) have shown an ability to reduce emissions below 2 ppmv NOx. Accordingly, the District has not shown that a BARCT level of 2 ppmv NOx is achievable over the broad spectrum of refinery heaters and boilers subject to the proposed amendments. Therefore, 5 ppm is a more appropriate endpoint for refinery boilers/heaters.

The same is true with respect to FCCUs. The District proposes a 2015 BARCT level of 2 ppm NOx based on the ability of one FCCU achieving the proposed level. As explained by the District's consultant, of the three FCCUs currently operating with SCRs, only one of them achieves less than 2 ppmv NOx.[12] Again, achievability in one unit does not guarantee similar performance in other units, particularly units that have been operating under different conditions for many years. Each refinery has unique circumstances such as equipment type, age, and
1-8 configuration that factor into its ability to achieve the proposed emission levels. Thus, what may be achievable for one piece of equipment may not be for another. Further, while there may be controls available with the ability to achieve the proposed level of performance, such control may come at a cost that is unreasonable. The District has not shown that the proposed levels can be achieved across the board in a cost effective manner. As a result, and to be consistent with the statutory obligations, the District needs to reconsider and revise the proposed BARCT levels to ensure that they are achievable by a more representative percentage of the sources subject thereto.

VI. Costs and Cost Effectiveness

Exclusion of the NEC cost estimates results in an inappropriate minimization of the estimated Refinery Sector costs presented in the PDSR. It also inflates the presented emission reductions estimate for the Refinery Sector. The BARCT analysis should be revised to explicitly reflect the

[11] WSPA/ERM confidential survey of WSPA members concerning refinery heaters/boilers, March 2015.
[12] Norton Engineering, *Comments on Preliminary Draft Staff Report Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM-SCRs for FCCUs Document No. 14-045-7* (August 10, 2015).

NEC cost estimates for Refinery Sector categories. Additionally, use of the Discounted Cash Flow (DCF) method along with interest rate and useful life assumptions make estimated costs for this rulemaking appear less expensive than they would be under the Levelized Cash Flow (LCF) method used by CARB and most other major Air Districts. WSPA believes that the LCF method is a better representation of cost effectiveness than the DCF method and recommends it be used. The same cost effectiveness threshold should be used for both DCF and LCF methods. Staff has used a higher cost threshold for LCF in the past than they used for DCF, so that the differences between the two methods are diluted.

1-9 The proposed $50,000 cost effectiveness threshold is greater than the AQMD's DCF cost effectiveness threshold for Command-and-Control sources in South Coast. Under the 2012 AQMP, the approved cost threshold for NOx control measures was $22,500 per ton,[13] and AQMD's current Best Available Control Technology (BACT) guidance document presents a cost effectiveness threshold that is only $19,100 per ton.[14] Also, the Health & Safety Code requires that market-based program costs be "equivalent or less compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the district's plan for attainment" and "the program will not result in disproportionate impacts, measured on an aggregate basis, on those stationary sources included in the program compared to other permitted stationary sources in the district's plan for attainment." [H&SC 39616(c)(1) and (7)]. Staff has not demonstrated that these legal obligations are satisfied. Therefore, WSPA recommends that the PDSR analysis be revised with the cost effectiveness threshold not greater than $22,500 (i.e., the cost effectiveness threshold used in the 2012 AQMP).

Further, the draft staff report understates the actual costs associated with meeting the proposed BARCT levels. As the District has done in past rulemakings, it hired NEC to provide reviews and recommendations on the analysis developed by SCAQMD as it relates to the technical feasibility of the control options as well as the cost effectiveness of each option. After gathering information from onsite visits to six of the refineries, NEC provided the District with a comprehensive evaluation of costs of each control option, the size and space needed for the equipment, and the time needed to install the control technologies. The District, however, chose to use different cost estimation approaches, opting to selectively disregard its own consultant's evaluation. This information was site specific and should be considered more credible than the
1-10 District's generic evaluation of costs. It is a hallmark of reasoned decision-making that an agency use the most accurate available information.

Apart from WSPA's concern relating to the dismissal of NEC's evaluation, the District's estimates do not include all of the costs that are required to be considered, and therefore vastly understate the cost impacts of the BARCT proposed. It appears that installation, design, and engineering costs have not been included properly. Moreover, it is critical to recognize that each refinery is unique such that BARCT levels achievable and cost effective at one refinery may not be at another. Plant configuration, equipment type, equipment age, length of time the SCR must remain in service and consistently achieving emission reduction targets between maintenance opportunities (most FCCUs, heaters, and boilers operate for years at a time, 24 hours per day and

[13] SCAQMD, 2012 AQMP, December 2012, pages 4-43.
[14] SCAQMD, BACT Guidelines, Part C: Policy and Procedures for Non-Major Polluting Facilities, 2006.

7 days per week), and composition of fuel, are a few of the factors in play with determining the costs associated with achieving the proposed levels. For example, some refinery configurations such as processes that utilize dual stacks, may require more than one SCR, and thus greater expenditures (i.e., double), to achieve the proposed level. It does not appear that such a scenario was considered by the District in developing its cost effectiveness determinations.

Accordingly, WSPA believes that the District's cost effectiveness calculations significantly understate the costs associated with achieving the proposed BARCT levels. We believe that even the Norton analysis underestimates actual costs. WSPA is currently developing additional information based on detailed engineering assessments that more accurately represent the costs associated with the proposed BARCT. We will submit this information to the record as it becomes available.

VII. Disproportionate Impacts

Under Health and Safety Code Section 39616(c)(7), the District must show that RECLAIM facilities are not being disproportionately impacted by participating in the program.[15] The draft staff report, noting the emission projections described in the 2012 AQMP, indicates that RECLAIM sources make up 37 percent of the projected NOx emissions for 2023 from stationary sources.[16] Table 2.1 of the draft staff report indicates that non-RECLAIM sources, including waste disposal and miscellaneous processes, will account for 46 tons per day of the annual average NOx emissions for the 2023 base year while RECLAIM sources (pre-shave) will account for 27 tons per day.[17]

1-11

In its proposal, the District is seeking substantial reductions from RECLAIM sources, the majority of which come from the nine refineries in the Basin. Nonetheless, there is nothing in the draft staff report or other proposal document that indicates what reductions will be required for non-RECLAIM facilities. In fact, there is no evidence presented that would lead the Board to make a finding that RECLAIM facilities are not taking the brunt of the load when it comes to requiring emission reductions. The District has failed to provide "appropriate information" to "substantiate" a finding of no disproportionate impact.

Indeed, for the Board to make such a finding, there must be evidence indicating that non-RECLAIM facilities are, on an aggregate basis, required to reduce their NOx emissions at the levels required by their RECLAIM counterparts (at least proportionately). Non-RECLAIM facilities represent the majority of the stationary NOx emissions, yet SCAQMD appears to be seeking *no* reductions from such sources. Barring appropriate information showing that non-RECLAIM sources are required to reduce emissions equivalent to what is proposed by these amendments, the Board cannot make the required findings and as a result, the proposed amendments violate the District's statutory mandate.

---

[15] Health & Saf. Code § 39616(c)(7).
[16] SCAQMD, *Preliminary Draft Staff Report, Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM* (Draft NOx RECLAIM Staff Report), p. 14. (July 21, 2015)
[17] *Id.*

VIII. Energy Efficiency Projects

1-12 Staff suggests that there are NOx emission co-benefits available from Refinery Sector sources due to energy efficiency projects that are in addition to the projected emission reductions under this rule. This is essentially an erroneous assumption due to the fact that the AQMD is relying on information that was submitted under the California AB32 Energy Efficiency and Co-Benefits regulation and most of the projects that were presented by Refinery Sector facilities in those 2011 vintage reports were already completed. As such, those emissions benefits were already reflected in the 2011 baseline year emissions presented in the PDSR. AQMD Staff acknowledges as much in PDSR Table 3.2. As such, these co-benefit reductions should not be presented or characterized as a potential additional benefit.

IX. Socioeconomic Impacts

1-13 Under Health and Safety Code Section 40728.5, the District is required to perform an analysis of the socioeconomic impacts of the proposed regulation. This assessment is important because it lays out the range of probable economic impacts to the regulated industries as well as the impact on the economy of the region as a whole. Unfortunately, the socioeconomic impacts analysis is not available at this time. WSPA believes that reviewing the analysis is important to its ability to meaningfully comment on these proposed regulatory changes. Accordingly, WSPA may change or supplement its comments on review of the analysis when it is released.

Thank you for considering the comments addressed in this letter. We look forward to continuing to work with you and your Staff on this important rulemaking. WSPA reserves the right to file additional comments or other materials as this rulemaking progresses.

Sincerely,

Suzanne E. Bonnicke

cc: Dr. Barry Wallerstein
Joe Casmassi

ATTACHMENT 1

ADDITIONAL COMMENTS ON PRELIMINARY DRAFT STAFF REPORT (PDSR) FOR NO_X RECLAIM AMENDMENTS

	Page/Section	WSPA Comment
1-14	Page 2, Current Emissions and RTC Holdings.	AQMD should use 2012 compliance year emissions as the baseline year for "current emissions" for all industrial sectors. WSPA understands the rationale presented by AQMD for use of 2012 data to characterize baseline Power Sector emissions. However, non-Power RECLAIM facilities were also exhibiting lower output levels in 2011 due to the recession that started in 2007. This is shown in attached Figure 1. Looking at certain key industrial sectors yields a similar conclusion. On a sectoral level, publicly reported economic data (see Figure 2A and Figure 2B) shows that economic output and emissions for the cement and textile manufacturing sectors in AQMD were also still recovering from recessionary low points in 2011. For these reasons, WSPA recommends that AQMD revise the Staff Report to use 2012 compliance year emissions as the baseline emissions year for all industrial sectors.
1-15	Page 3: Table EX-1, Summary of Proposed BARCT (May 2015).	Table EX-1 presents data for the Refinery Sector which fails to reflect changes necessitated by the findings of the third-party expert hired to confirm the AQMD Staff's Refinery Sector technical analysis for this rulemaking. The Staff's BARCT analysis for the Refinery Sector categories should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review.[1] The third-party experts were hired to confirm the AQMD Staff's technical analysis in support of this rulemaking. By selectively dismissing the third-party refinery sector expert's findings without resolution of the technical issues in dispute, AQMD Staff have compromised the rulemaking process. We also note that NEC has raised a significant number of technical issues with the conclusions presented in the PSDR for the Refinery Sector categories.[2] WSPA strongly suggests that these technical issues be resolved before further presentation of emissions reductions attributable to the proposed BARCT analysis.
1-16	Page 3. Last paragraph, 3rd sentence. Resolution of Uncertainties	WSPA recommends this section be re-written after the requested and required changes to the Staff's BARCT analysis have been completed. The subject paragraph suggests that Staff has "accounted for uncertainties that arose in the BARCT analysis…." We disagree. There continues to be a significant number of unresolved issues which result in uncertainty in the Staff analysis presented in the PDSR. This includes, but is not limited to the Staff's decision to selectively ignore the findings of the agreed upon third-party expert for the Refinery Sector.

[1] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM - BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.

[2] James Norton, NEC, letter to Dr. Philip Fine, SCAQMD, Comments on Preliminary Draft Staff Report Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM – SCRs for FCCUs Document No. 14-045-7, 10 August 2015.

1-17	Page 3. Last paragraph, 3rd sentence. Proposed Adjustment Account	The proposed "Adjustment Account" should be accessible by all RECLAIM facilities subjected to the Rule 2005 NSR RTC holding requirement. Furthermore, AQMD Staff should provide a technical rationale to support the quantity of RTCs set aside to fund any such adjustment account. The PDSR suggests the RTC demand caused by Rule 2005 RTC holding requirements are addressed by the proposed creation of an RTC Adjustment Account for power plants. However, the RTC holding requirements imposed under Rule 2005 are also applicable to many non-Power Sector facilities under RECLAIM New Source Review. The Staff's current proposal does nothing to address the RTC demand associated with these non-Power Sector facilities. This should be resolved.
	Page 3. Last paragraph, 3rd sentence. Proposed Adjustment Account	AQMD Staff should provide a regulatory discussion detailing how this proposed Adjustment Account would be managed, and how RTCs in the account would be treated with respect the to the State Implementation Plan (SIP).
1-18	Page 3. Last paragraph, 5th sentence. Compliance Margin	WSPA recommends this section be re-written to eliminate potential misstatements concerning the level of "unused RTCs" that might be available under the Staff's proposed shave. The Staff's "Remaining Emissions" approach as presented in the PDSR limits the overall "Compliance Margin" for RECLAIM facilities to 10% of projected 2023 emissions (i.e., not 23%). The Staff's Remaining Emissions estimate excludes some RECLAIM market sectors (i.e., cement) which had reduced emissions in 2011 due to the major recession from which certain sectors were still recovering. Staff has made an adjustment to account for that omission, but this paragraph then suggests that such adjustment is part of the overall market's Compliance Margin. That is incorrect.
1-19	Page 4: 1st full paragraph. Application of Shave	The proposed NOx RECLAIM shave should be applied in an equally distributed, "Across the Board" manner consistent with RECLAIM founding principles and the precedent set under the 2005 NOx RECLAIM shave. RECLAIM is a market-based program which was designed to use "the power of the marketplace"[3] to reduce air emissions from stationary sources. This approach was expressly intended not to impose "command-and-control" requirements on specific facilities or specific equipment therein. Rather, RECLAIM was intended to provide Southern California businesses with greater flexibility and a financial incentive to reduce air pollution at least equal to what traditional command-and-control rules would have required. This program has been very successful in reducing NOx emissions with RECLAIM facilities having reduced their overall actual emissions well in excess of the program's current target under Regulation XX.

[3] SCAQMD RECLAIM website, http://www.aqmd.gov/home/programs/business/business-detail?title=reclaim.

		The District has previously considered and rejected targeted shaves as noted in the excerpts below: • Oct 1993, RECLAIM Program Summary: "Throughout the development of RECLAIM, the District evaluated several design options that would have treated some industries differently than others……After evaluating advantages and disadvantages, the District adopted a program that treats all sources consistently for equity and fairness." • 2005 Staff Report, Appendix E: "The Staff proposal is taking the "across-the-board" reduction of NOx RTC holdings approach by looking at the total reductions possible based on BARCT determinations and reducing allocations for all RTC holders by the same percentage…This approach, from a market design standpoint and based on the overall conceptual design of the RECLAIM program to achieve programmatic BARCT, is the most equitable…" The Staff proposal presented in the PDSR is inconsistent with the founding principles of the RECLAIM program that stressed the importance of a market-based program, as well as the precedent established by the SCAQMD in previous NOx regulatory reductions in 1999 and 2005. An equally distributed "across-the board" treatment of all sources, as originally designed and implemented since the program's inception in 1994, is critical to the continued success of the RECLAIM program.
1-20	Page 4: 1st full paragraph, 3rd sentence. Small Facilities	This sentence states "The remaining 210 facilities that hold 10% of the 26.5 tpd RTC are not proposed to be shaved because there was no new BARCT for the types of equipment and operation at these facilities." This statement is factually incorrect and should be corrected. AQMD Staff opted not to review BARCT for these facilities under this RECLAIM rulemaking. Additionally, AQMD and other California air districts have previously made BARCT determinations that would apply to the equipment and operations at those smaller emitting facilities (e.g., boilers, heaters, etc.) were they not under RECLAIM.[4]
1-21	Page 4: 2nd and 3rd full paragraphs. Implementation Schedule	The proposed Implementation Schedule should be revised to shave not more than 2 tons per day (tpd) from the program in the first year. This is consistent with Governing Board's direction under Control Measure CMB-01 Phase 1. Additionally, the overall schedule should be longer than the proposed seven (7) years to ensure RECLAIM facilities have sufficient time to comply. 2012 Air Quality Management Plan (AQMP) Control Measure CMB-01) Phase 1 was approved by the Governing Board on the basis that 2 tpd would be removed from RECLAIM in the event of the $PM_{2.5}$ contingency measure being triggered.[5] The proposed schedule should be consistent with that 2 tpd State Implementation Plan (SIP) commitment; anything

[4] See SCAQMD Regulation XI for examples.
[5] SCAQMD, 2012 AQMP. Page 4-9 states: "The control measure will seek further reductions of 2 tpd of NOx allocations if triggered." Appendix A, page IV-A-13 presents rationale for that conclusion.

		larger may not allow sufficient time for industry to implement emission control projects necessitated by the rulemaking. Also, the proposed schedule for full implementation by 2022 may be insufficient to achieve the proposed level of NOx emission reductions from RECLAIM facilities. Refinery Sector sources may need 8 years or more to fully engineer, permit, construct and operationalize all the projects needed to comply with the proposed rulemaking.[6]
1-22	Page 6: Table EX-2, Summary of Public Process.	To provide ample opportunity for stakeholder review and comment, AQMD Staff should revise this schedule to provide the public with a realistic schedule for this rulemaking that includes the CEQA Program Environmental Assessment (PEA) and the Socioeconomic Analysis.
1-23	Page 19: Co-Benefits of Energy Efficiency Projects.	This section should be completely removed from the PDSR or significantly revised to correct factual mischaracterizations. The information submitted by refineries to the California Air Resources Board in 2011 under the AB32 Energy Efficiency and Co-Benefits regulation reflected projects that mostly had been completed by 2011. Thus, those co-benefits were already reflected in the 2011 baseline year emissions presented in the PDSR and cannot be characterized as additional or creditable. Staff have acknowledged as much in PDSR Table 3.2.
1-24	Page 29 CEQA Alternatives	The size of the shave approved in the 2012 AQMP should be included in the list of CEQA alternatives.
1-25	Chapter 4: Costs and Cost Effectiveness. Cost Thresholds	The cost effectiveness threshold for this rulemaking should not be greater than $22,500 (i.e., the cost effectiveness threshold used in the 2012 AQMP) and the BARCT analysis presented in the PDSR should be revised accordingly. The $50,000 cost effectiveness threshold proposed by AQMD Staff is greater than the AQMD's DCF cost effectiveness threshold for Command-and-Control sources in South Coast. Under the 2012 AQMP, the approved cost threshold for NOx control measures was $22,500 per ton. As an additional data point, AQMD's current Best Available Control Technology (BACT) guidance document presents a DCF cost effectiveness threshold of only $19,100 per ton. Health & Safety Code (H&SC) §39616(c) requires that market-based program costs will be "equivalent or less compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the district's plan for attainment" and also requires "the program will not result in disproportionate impacts, measured on an aggregate basis, on those stationary sources included in the program compared to other permitted stationary sources in the district's plan for attainment."[7] The AQMD Staff analysis presented in the PDSR has not demonstrated that these obligations are satisfied.
	Chapter 4: Costs and Cost Effectiveness.	A 10-year "Useful Life" assumption is more appropriate given actual rulemaking timetables; the BARCT analysis presented in the PDSR should be accordingly revised to use a 10-year Useful Life assumption.

[6] Stillwater Associates LLC, RECLAIM Analysis for WSPA, July 2015.
[7] Health & Safety Code §39616(c)(1) and (7).

1-26	Useful Life Assumption	The AQMD Staff's proposed 25-year Useful Life is inappropriate because AQMD rulemaking occurs on a far more frequent recurrence. The last major NOx RECLAIM rulemaking was only 10-years ago. Use of a 25-year assumption makes the rule costs appear lower than actual by diluting the significant capital costs of required projects over a much longer time table than is likely to occur. The AQMD Staff analysis should be revised to reflect the 10-year Useful Life assumption which is more consistent with recent AQMD rulemaking schedules and is also consistent with the Useful Life assumption typically used by CARB and other major Air Districts.
1-27	Chapter 4: Costs and Cost Effectiveness. DCF Method	The BARCT analysis presented in the PDSR should be revised to utilize the Levelized Cash Flow (LCF) methodology used by CARB and other major air districts. Use of the DCF method, in combination with the proposed interest rate and Useful Life assumptions serves to distort the estimated costs for this AQMD rule by making them appear less expensive than they would be using the Levelized Cash Flow (LCF) method employed by CARB and other major Air Districts. The same threshold should be used for both DCF and LCF.
1-28	Chapter 5: RTC Reductions, Remaining Emissions Remaining Emissions Method	The AQMD Staff's "Remaining Emissions" method conflicts with Control Measure CMB-1 Phase 1 as approved under the 2012 AQMP and should be replaced with the Incremental BARCT method proposed by the Industry RECLAIM Coalition. The Remaining Emissions method presented in the PDSR conflicts with Control Measure CMB-1 Phase 1 because it would remove nearly all Unused RTCs (i.e., "surplus") from RECLAIM. CMB-01 Phase 1 explicitly considered and rejected such a reduction; instead arguing that a 2 tpd of reduction for Unused RTCs was more appropriate due to concerns that baseline RECLAIM emissions might reflect the economic downturn.[8] As noted above, many Southern California industry sectors covered by RECLAIM were in fact still under a recessionary hangover in 2011 so such concerns were valid. Furthermore, the "Incremental BARCT" method is more consistent with Control Measure CMB-1 Phase 2 approved under the 2012 AQMP[9] because the method would only remove RTCs in an amount attributable to technology advancement (i.e., BARCT). AQMD Staff's own analysis demonstrates that less than 9 tpd of proposed RTC reductions are attributable to the 2015 BARCT analysis. Yet the Staff proposal proposes to shave 14 tpd. Removing RTCs beyond what is supported by technology advancement may subject facilities in the RECLAIM program to disproportionate impacts, measured on an aggregate basis, compared to other permitted stationary sources in the District's plan for attainment. It may also subject

[8] SCAQMD, 2012 AQMP. Page 4-9 states: "The control measure will seek further reductions of 2 tpd of NOx allocations if triggered." Appendix A, page IV-A-13 presents rationale for that conclusion.
[9] SCAQMD, 2012 AQMP. Page 4-26 states: "This phase of control is to implement periodic BARCT evaluation as required under the state law." Appendix A, page IV-A-60 presents more detailed discussion for the measure.

	RECLAIM facilities to greater costs compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment. Either of these outcomes would conflict with H&SC 39616(c). AQMD has not demonstrated that the Staff proposal successfully meets these obligations. Further, under Section 40727, the Legislature has established that regulations must meet the requirements of necessity, authority, clarity, consistency, non-duplication, and reference. The necessity requirement ensures in part that unnecessary costs are not imposed on the economy of California. Accordingly, the District needs to establish that the shave is no more stringent than what is "necessary." Necessity "means that a need exists for the regulation, or for its amendment or repeal, as demonstrated by the record of the rulemaking authority."[10] Through the 2012 AQMP, SCAQMD has described that a need exists for a reduction in NOx emissions. The ceiling of that need was five tons per day. The magnitude of the current shave proposal goes above and beyond what is necessary to meet the requirements of the AQMP or any other statutory or regulatory obligation that SCAQMD faces.

1-29

Chapter 5: RTC Reductions, Remaining Emissions Compliance Margin	The proposed Compliance Margin of 10% appears inadequate to meet the market's historical need for Unused RTCs and should be revised to the 20-30% range. The RECLAIM market has exhibited "Unused RTCs" since program inception. This may be for several reasons including facility compliance margins which range in size depending on facility size and/or risk tolerance, RTC holding requirements imposed under Rule 2005, or market trading to name few. These Unused RTCs have historically averaged in the 15-30% range (5 to 9 tpd) with the sole exception being the market crisis during the 2000 compliance year.[11] The AQMD Staff's proposal (with only 10% compliance margin) may be inadequate for satisfying this market requirement. Excessive shaving of Unused RTCs could result in a market which is unable to accommodate the economic activity levels projected in the Staff's analysis. Furthermore, removal of all Unused RTCs would directly conflict with Control Measure CMB-01 Phase 1 as authorized by the Governing Board.
Chapter 5: RTC Reductions, Remaining Emissions Table 5.1 – Remaining Emissions for Refinery Sector (May 2015)	The BARCT analysis for the Refinery Sector categories should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review, and Table 5.1 should be accordingly revised. As noted in the PDSR, the Staff analysis fails to account for the technical recommendations from NEC, the third-party Refinery Sector expert hired by the AQMD. NEC's findings have material impacts on the resulting BARCT determinations for certain Refinery Sector categories. Once corrected, the projected "2023 Remaining Emissions at 2015 BARCT" for the Refinery Sector will increase, and the "2023 Emission Reductions Beyond 2000/2005 BARCT" will decrease. These technical corrections are critical to a fair application of the proposed shave.

1-30

[10] Health & Saf. Code § 40727.
[11] SCAQMD, Annual RECLAIM Audit Report for 2013 Compliance Year, 6 March 2015. See Table 3-2.

	Appendix A - Refinery Fluid Catalytic Cracking Units (FCCUs) Page 53. Incremental Costs and Cost Effectiveness Cost Effectiveness Calculations	The cost effectiveness analysis presented for FCCUs in Appendix A does not consider the 2000/2005 BARCT emissions or cost baselines. This conflicts with the methodology outlined in Chapter 4. The Staff BARCT analysis should be accordingly revised based on the incremental cost effectiveness approach outlined in Chapter 4. Staff proposes that the cost effectiveness of 2015 BARCT is to be calculated based on the incremental cost of progressing from 2000/2005 BARCT to the proposed 2015 BARCT level, divided by the incremental emissions benefit related to the progression from 2000/2005 BARCT to the proposed 2015 BARCT level (i.e., "2023 Emission Reductions Beyond 2000/2005 BARCT"). For some reason, it was not applied in this manner for the FCCUs. We request that this oversight be corrected.
1-31	Appendix A - Refinery Fluid Catalytic Cracking Units (FCCUs) Page 53. Incremental Costs and Cost Effectiveness Consideration of Third-Party Expert's Recommendations on Cost	The Staff's BARCT analysis for the Refinery FCCUs category should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review.[12] The third-party experts were hired to confirm the AQMD Staff's technical analysis in support of this rulemaking. By selectively dismissing the third-party refinery sector expert's findings, without resolution of the technical issues in dispute, AQMD Staff have compromised the rulemaking process. We also note that NEC has raised a significant number of technical issues with the conclusions presented in the PSDR for the Refinery FCCUs which have reportedly been discussed with Staff and were reiterated in NEC's letter dated 10 August 2015.[13] Norton's comments are attached hereto and incorporated herein by reference. These technical issues are significant and should be resolved before any further characterization of emissions reductions attributable to proposed BARCT under the Staff's analysis.
1-32	Appendix B – Refinery Boilers and Process Heaters Page 60, Achieved-In-Practice NOx Levels for Boilers and Heaters Proposed BARCT	WSPA requests further technical demonstration to support the proposed BARCT level for refinery heaters and boilers; the proposed BARCT level does not appear to represent an achievable level of performance for most refinery heaters/boilers operating on refinery fuel gas. According to the AQMD's figures, fewer than 10% of the heater/boiler units already equipped with SCR technology are able to achieve the proposed BARCT level. This does not suggest the performance level can be broadly achieved with add-on emissions controls. If this level of performance effectively demands basic equipment replacement, the AQMD's BARCT analysis should identify and quantify costs for that demand. WSPA also requests clarification on the number of refinery heaters and boilers reported to that have "very low emissions levels." AQMD Staff have provided conflicting counts to stakeholders, and those counts conflict

[12] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM - BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.
[13] James Norton, NEC, letter to Dr. Philip Fine, SCAQMD, Comments on Preliminary Draft Staff Report Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM – SCRs for FCCUs Document No. 14-045-7, 10 August 2015.

		with information provided to WSPA directly by WSPA member refineries.[14] The PDSR reports fourteen refinery heaters in the AQMD as using refinery fuel gas and achieving NOx concentrations "between 1.6 and 3.5 ppmv" (corrected to 3% O2) using Selective Catalytic Reduction (SCR) technology. AQMD Staff also report that two boilers have achieved NOx emissions between 2 and 5 ppmv using LoTOx scrubbers and natural gas. We understand that AQMD's analysis is based on data collected from Southern California refineries under a 2013 survey.[15] AQMD had previously reported to the RECLAIM Working Group that, based on that same survey, only nine refinery heaters/boilers were achieving below 5 ppmv. WSPA requests clarification on how this count of units with "very low emissions levels" could have changed. Lastly, AQMD should not categorize units between performing "between 1.6 and 3.5 ppmv" as a single group consistent with the proposed BARCT. 3.5 ppmv does not equal 2 ppmv, and some units which achieve 3.5 ppmv may be unable to meet 2 ppmv even with add-on controls. We would suggest this group supports a BARCT determination of 3.5 ppmv; not 2 ppmv.
1-33	Appendix B – Refinery Boilers and Process Heaters Page 60, Achieved-In-Practice NOx Levels for Boilers and Heaters Cost Basis for BARCT and Consideration of Third-Party Expert's Recommendations on Cost	The Staff's BARCT analysis for the Refinery heaters and boilers should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review, and any subsequent comments from NEC.[16] The third-party experts were hired to confirm the AQMD Staff's technical analysis in support of this rulemaking. By selectively dismissing the third-party refinery sector expert's findings without resolution of the technical issues in dispute, AQMD Staff have compromised the rulemaking process. The AQMD Staff's analysis suggests that the proposed BARCT level of 2 ppmv can be achieved with less equipment (e.g., 1 layer of catalyst) and less cost than suggested by the third-party Refinery expect; a firm that engineers such equipment as its primary business. Counter to the AQMD Staff's assertion that NEC was simply wrong on its design basis is the fact (reported by AQMD)[17] that fewer than 10% of the existing Refinery heaters/boilers with SCR technology are able to meet 2 ppmv. This result includes both new and retrofit installations and suggests that the proposed 2 ppmv NOx performance level may not be as easily achieved as suggested by Staff. Given the material impact of these technical issues on the BARCT analysis, they should be resolved before any further characterization of emissions reductions attributable to proposed BARCT under the Staff's analysis. Specifically, we request that the BARCT analysis presented in Appendix B be revised to consider the cost estimates presented by NEC.
	Appendix B – Refinery	The BARCT cost effectiveness analysis presented in this table suggests

[14] WSPA/ERM confidential survey of WSPA members concerning refinery heaters/boilers, Mar 2015.
[15] SCAQMD, Preliminary Draft Staff Report (PDSR) for Proposed Amendments to NOx RECLAIM, 21 July 2015.
[16] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM - BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.
[17] SCAQMD, NOX RECLAIM Working Group Meeting, 19 September 2013.

1-34	Boilers and Process Heaters Table B.11 - Details of Cost Estimates for Boilers and Heaters (March 2015)	AQMD Staff have selectively applied the methodology outlined in Chapter 4. This is specifically a problem for select heaters which are reportedly already meeting proposed BARCT. In these instances, Staff has claimed emissions reductions relative to the 2000/2005 BARCT level without assigning any programmatic costs for those reductions. This is inconsistent with the programmatic approach outlined in Chapter 4, under which cost effectiveness of 2015 BARCT is to be calculated based on the incremental cost of progressing from a 2000/2005 BARCT level to the proposed 2015 BARCT level, divided by the incremental emissions benefit related to the progression from 2000/2005 BARCT to the proposed 2015 BARCT level (i.e., "2023 Emission Reductions Beyond 2000/2005 BARCT"). WSPA does not believe it appropriate for Staff to selectively "pick and choose" when use the prescribed programmatic approach. The Staff BARCT analysis should be revised accordingly to be fully consistent with the incremental cost effectiveness approach outlined in Chapter 4.
1-35	Appendix D - Coke Calciner Staff's Recommendation	WSPA appreciates that AQMD Staff accepted NEC's recommended BARCT level of 10 ppmv and has incorporated it into the BARCT analysis for this source category.
1-36	Appendix E - Sulfur Recovery Units/Tail Gas Incinerators Page 110. Costs and Cost Effectiveness Design Basis for BARCT and Consideration of Third-Party Expert's Recommendations	The Staff's BARCT analysis for the Refinery Sulfur Recovery Units/Tail Gas Incinerators (SRU/TG Incinerators) category should be revised to explicitly consider the findings presented in Norton Engineering Consultants' (NEC) BARCT Feasibility and Analysis Review.[18] The third-party experts were hired to confirm the AQMD Staff's technical analysis in support of this rulemaking. As with other categories, the AQMD Staff's analysis suggests that the proposed BARCT level of 2 ppmv can be achieved for SRU/TG Incinerators with less equipment (e.g., fewer layers of catalyst) and less cost than suggested by the third-party Refinery expert; a firm that engineers such equipment as its primary business. By selectively dismissing the third-party refinery sector expert's findings without resolution of the technical issues in dispute, AQMD Staff have compromised the rulemaking process. Given the impact of these technical issues on the projected emissions and costs for this category, these issues should be resolved before any further characterization of emissions reductions attributable to proposed BARCT under the Staff's analysis. Specifically, we request that the BARCT analysis presented in Appendix E be revised to consider the cost estimates presented by NEC. Tables E.1 and E.2 should include NOx concentration levels.
1-37	Appendix K – Co-Benefits of Energy Efficiency Projects	This appendix should be completely removed from the PDSR or significantly revised to correct factual mischaracterizations.

[18] Norton Engineering Consultants (NEC), SCAQMD NOx RECLAIM - BARCT Feasibility and Analysis Review, Non-Confidential Final Report No. 14-045-4, 26 November 2014.

	The information submitted by refineries to the California Air Resources Board in 2011 under the AB32 Energy Efficiency and Co-Benefits Regulation reflected projects that had mostly been completed by 2011. Thus, those co-benefits were already reflected in the 2011 baseline year emissions presented in the PDSR and cannot be characterized as additional or creditable. Staff have acknowledged as much in Table K.1 and also PDSR Table 3.2.

1-38

Part III – RTC Reduction Approaches Appendix U – Staff's Proposal and CEQA Alternatives	The proposed NOx RECLAIM shave should be applied in an equally distributed, "Across the Board" manner consistent with RECLAIM founding principles and the precedent set under the 2005 NOx RECLAIM shave. RECLAIM is a market-based program which was designed to use "the power of the marketplace"[19] to reduce air emissions from stationary sources. This approach was expressly intended not to impose "command-and-control" requirements on specific facilities or specific equipment therein. Rather, RECLAIM was intended to provide Southern California businesses with greater flexibility and a financial incentive to reduce air pollution at least equal to what traditional command-and-control rules would have required. This program has been very successful in reducing NOx emissions with RECLAIM facilities having reduced their overall actual emissions well in excess of the program's current target under Regulation XX. The District has previously considered and rejected targeted shaves as noted in the excerpts below: • Oct 1993, RECLAIM Program Summary: "Throughout the development of RECLAIM, the District evaluated several design options that would have treated some industries differently than others……After evaluating advantages and disadvantages, the District adopted a program that treats all sources consistently for equity and fairness." • 2005 Staff Report, Appendix E: "The Staff proposal is taking the "across-the-board" reduction of NOx RTC holdings approach by looking at the total reductions possible based on BARCT determinations and reducing allocations for all RTC holders by the same percentage…This approach, from a market design standpoint and based on the overall conceptual design of the RECLAIM program to achieve programmatic BARCT, is the most equitable…" The Staff proposal presented in the PDSR is inconsistent with the founding principles of the RECLAIM program that stressed the importance of a market-based program, as well as the precedent established by the SCAQMD in previous NOx regulatory reductions in 1999 and 2005. An equally distributed "across-the board" treatment of all sources, as originally designed and implemented since the program's inception in

[19] SCAQMD RECLAIM website, http://www.aqmd.gov/home/programs/business/business-detail?title=reclaim.

	1994, is critical to the continued success of the RECLAIM program.

SUPPORTING FIGURES

Figure 1. U.S. Excluding California, California Excluding SCAQMD, and SCAQMD Output Index, All Regulated Industries Combined, 1997-2012 (Source: Kavet, Rockler & Associates based on data from his IHS County-Level Economic Database, 2015)

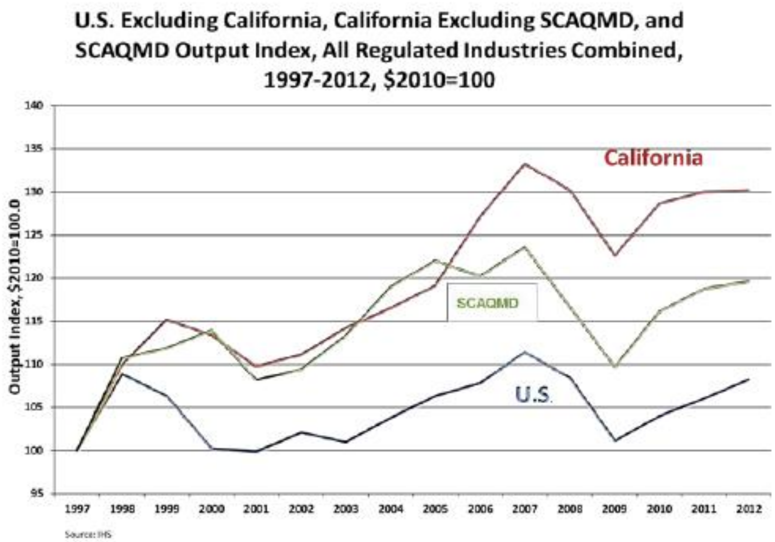


Figure 2A. South Coast AQMD Region Cement Output and Emissions, 1997-2012 (Source: Kavet, Rockler & Associates based on data from his IHS County-Level Economic Database, 2015)

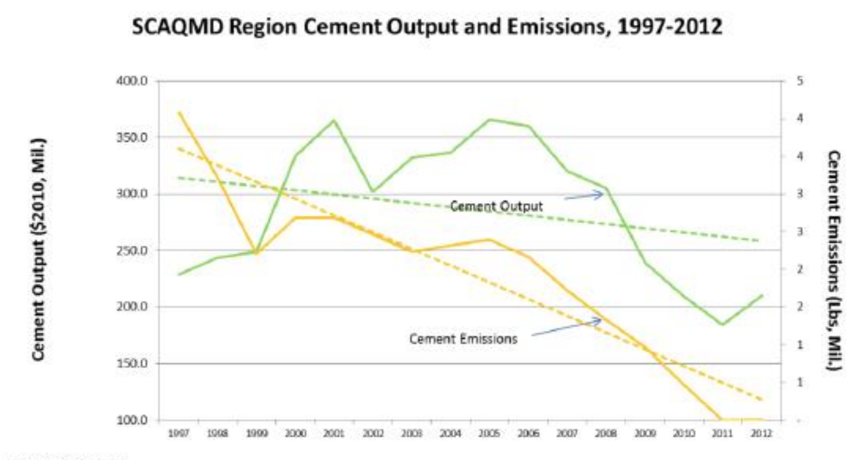
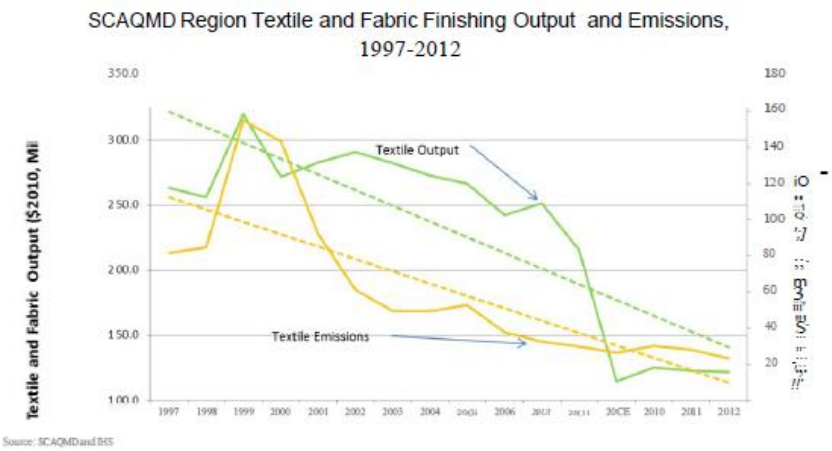


Figure 2B. South Coast AQMD Region Textile and Fabric Finishing Output and Emissions, 1997-2012
(Source: Kavet, Rockier & Associates based on data from his IHS County-Level Economic Database, 2015)



Responses to Letter #1

Response 1-1 Previous WSPA Comment Letters

Please see staff's responses to previous WSPA and the Industry Coalition's letter and comments attached to the Draft Socioeconomic Staff Report.

Response 1-2 Shave Methodology and Arbitrary Removal of Unused RTCs

Staff disagrees with the commenter's assessment in several areas.

Intent of Control Measure CMB-01 and RTC Reductions

It is important to understand that the Basin is currently classified as a "severe" non-attainment area for PM2.5 and "extreme" non-attainment for ozone. Based on recent data, the Basin did not meet the PM2.5 ambient air quality standards by the original attainment date of 2014 or the revised attainment date of 2015. Thus, staff is obligated to find all technological feasible and cost-effective control technologies to help the Basin achieve maximum emission reductions and attain the PM2.5 and ozone ambient air quality standards as expeditiously as possible. Control Measure CMB-01 is a control measure in the 2012 AQMP that called for a total NOx reduction of 3-5 tpd in 2 phases: 2-3 tpd in Phase I with implementation date in 2014 (already overdue) and 1-2 tpd in Phase II with implementation date in 2020.[7, 8] Staff committed to submit 3 tpd, the lower end of the range, to satisfy the SIP commitment. The intent of the Control Measure CBM-01 was not to limit the reduction to 3-5 tpd:[9]

> *"It should be noted that since there are substantial NOx reductions needed by 2023, if additional reductions are feasible and cost effective, they will be evaluated during rulemaking."*

The control measure also states that the District is required to monitor advances in BARCT, and if BARCT advances, the District is required to periodically re-assess the overall facility caps, and reduce the RTC holdings to applicable equivalent command & control BARCT levels.

---

[7] The implementation dates are shown in Tables 4-2 and 4-4 of the 2012 AQMP

[8] The 2 tpd in the statement that WSPA cited "The control measure will seek further reductions of 2 tpd NOx allocations if triggered" on page 4-9 of the 2012 AQMP refers to the additional 2 tpd in Phase 2.

[9] Page IV-A-60, Appendix IVA of the 2012 AQMP

Staff has identified and evaluated all feasible and cost-effective BARCT to achieve 14 tpd RTC reduction as proposed in the PDSR. As stated in Control Measure CMB-01, the Control Measure did not limit the reduction to 3-5 tpd. There is no language in control measure CMB-01 that explicitly considered and rejected removing more than 2 tpd of unused RTCs.

Regarding the implementation schedule for the 14 tpd RTC reduction, in the 5 years from 2009-2013, the unused RTCs in the NOx RECLAIM program ranged from 5 to 8 tpd, [10] thus staff is proposing a 4 tpd RTC reduction in 2016. Additional reduction from implementation of BARCT will take 2 - 4 years for procurement, engineering, planning, and construction, therefore staff is proposing that the remaining shave of 10 tpd take place over 5 years between 2018 and 2022.

Methodology for BARCT Reductions & Removal of Unused RTCs

On contrary with the commenter's assessment, Control Measure CMB-01 from the 2012 AQMP does not prescribe how the shave should be calculated and thus it is not in conflict with the shave methodology. The proposed shave in the RECLAIM program is estimated based on remaining emissions. This proposed method is consistent with past practice in the 2005 and 2010 RECLAIM amendments.

To calculate the shave, staff first estimated the remaining emissions at BARCT levels projected to the compliance year 2023 including economic growth and 10% compliance margin. The shave was calculated as the difference between the current RTC holdings and the remaining emissions projected to 2023. Staff also reduced the shave by 0.85 tpd to account for uncertainties and provide some additional compliance margin. The total shave proposes removal of RTCs necessary to attain BARCT levels of emissions, including removing some unused surplus RTCs in the market.

Shave = Current RTC Holdings – (2023 Remaining Emissions + Uncertainty)
= RTCs attributable to difference between 2000/2005 & 2015 BARCT + Portion of Unused RTCs
= 26.5 – (11.67 + 0.85) = 8.8 + 5.2 = 14 tpd

WSPA has suggested staff remove only the RTCs directly attributable to technology advancement (8.77 tpd) but not the unused RTCs. The unused RTCs however create a dampening effect on RTC prices that allows RECLAIM facilities to purchase RTCs in lieu of implementing BARCT. For example, in 2009-2013, there were about 5 – 8 tpd surplus RTCs in the market and the average RTC prices were in a range of $1,162 – $5,491 per ton compared to the average cost-effectiveness

[10] Table 1.1 of the Preliminary Draft Staff Report

of control range $8,300 - $13,000 per ton.[11, 12] Thus, the facilities opted to purchase low cost abundant surplus RTCs to reconcile their emissions at the end of the compliance year in lieu of installing control to reduce “real” emissions. For example, the refineries did not install any SCRs in responses to the 2005 NOx RECLAIM amendment even though staff had estimated about 51 SCRs would be installed by 2011. Removing surplus RTCs is therefore critically important to ensure the effectiveness of the RECLAIM program and meet state law requirements to require the use of BARCT for existing sources.

WSPA has suggested staff estimate the shave based the projected actual emissions but not the current RTC holdings.[13] However, removing 8.77 tpd from current RTC holdings will not be enough to ensure that the RECLAIM universe emits at an emission level that represents the maximum degree of reductions achievable as required by H&SC 40406. Staff analysis has shown that the RECLAIM universe can achieve a level of 12.5 tpd remaining emissions. To reduce RTCs from the current 26.5 tpd to reach the target of 12.5 tpd requires a “shave” of 14 tpd. A smaller shave would be met by simply giving up unused RTCs, not producing any significant actual emission reductions.

Compliance Margin

RECLAIM facilities typically hold extra RTCs in their account to ensure that they will have enough RTCs to reconcile their emissions at the end of the compliance year.[14] Plant operation and emissions may fluctuate. CEMS may be offline and facilities must use missing data procedures to calculate emissions which may be higher than actual emissions. Also, facilities may underestimate their actual emissions and need to hold a stream of RTCs to account for adjustments after audit. In previous RECLAIM amendments, staff provided 10% compliance margin to help the facilities deal with these uncertainties. Staff did the same in this amendment allowing a 10% compliance margin but actual unused RTCs may be even higher. As illustrated below, this level of compliance margin will result in 23% unused RTCs above the remaining emissions. Staff believes this will adequately meet the market’s need for unused RTCs.

---

[11] Discrete RTC prices shown in Figure 1.2 of the PDSR: $1,162 - $5,491 per ton for 2005-2012.

[12] Cost effectiveness for individual source categories: $11,000 - $17,000 per ton for refinery boilers/heaters >110 mmbtu/hr and FCCUs, $9,000 - $10,000 per ton for industrial boilers, $4,000 - $11,000 per ton for metal melting/heat treating and miscellaneous combustion (page 3 of the Board Letter for the 2005 NOx RECLAIM Amendment, Agenda No. 25, January 7, 2005). Overall program average cost effectiveness: $8,300 - $13,000 per ton (page 8 of the Board Letter for the 2005 NOx RECLAIM Amendment, Agenda No. 25, January 7, 2005).

[13] Industrial Coalitions’ Approach: Shave = Projected 2011 Emissions @ 2005 BARCT – Projected 2023 Emissions @2015 BARCT = 8.77 tpd. Staff’s Approach = RTC Holdings – 2023 Remaining Emissions – Adjustment = 14 tpd

[14] Page 54 the Staff Report of the 2005 NOx RECLAIM Amendment.

Remaining RTCs after shave = 26.5 tpd – 14 tpd = 12.5 tpd
Remaining emissions = 2.71 tpd (refinery) + 7.47 tpd (non-refinery) = 10.18 tpd
Surplus RTCs = 12.5 tpd – 10.18 tpd = 2.3 tpd
% Unused RTCs = 2.3 tpd / 10.18 tpd = 23% above remaining emissions

The compliance margin is not expected to meet the RTC holding requirements imposed under Rule 2005. Instead, staff has created a Regional NSR Holding Account to help facilities in the power sector subject to Rule 2005 NSR requirements. This Account will be taken from the 14 tpd shave and not from the post-shave unused RTCs. Staff has discussed this issue with the U.S. EPA to seek their approval on the concept and receive feedback on whether or not this concept can be applied to all RECLAIM facilities.

Staff believes the compliance margin is not needed to create market liquidity. It is envisioned that the facilities would install control equipment to reduce emissions to the BARCT levels as required by state law and would create surplus RTCs to trade and keep the market liquid.

Response 1-3 Shave Application and Implementation Schedule

At the inception of the RECLAIM program in 1993, the compliance year 2000 allocations were estimated for each facility in RECLAIM based on the methodology described in Rule 2002(d), and the compliance year 2003 allocations were estimated based on the methodology described in Rule 2002(e). There was no "across-the-board" uniform percentage shave.

In the 2005 NOx RECLAIM amendment, a uniform percentage shave (22.5%) was applied "across-the-board" because the BARCT identified at that time was applicable to "across-the-board" facilities (e.g. low NOx burners for ovens, kilns, furnaces.)

The shave for the SOx RECLAIM in 2010 was not distributed "across-the-board" because 1) the BARCT identified was applicable to only 11 major facilities,[15] and 2) the non-uniform characteristics of the market made it inequitable to distribute the shave to all facilities. [16] To ensure that the 11 major facilities would install BARCT equivalent to command-and-control and to keep other facilities in the market, the 2011 SOx shave was applied only to investors and one-third of the facilities in the SOx RECLAIM universe.

It should be noted that the methods used to establish the 1993, 2005 or 2010 shaves did not establish founding principles and precedence on how the shave must be distributed. How the shave

[15] The 11 major facilities included six refineries, a coke calciner, two sulfuric acid plants, a cement plant, and a glass plant.

[16] The 11 major facilities hold 87% of RTCs and contributed more than 94% of emissions. The remaining 21 facilities hold 6% of RTCs and contributed 6% of emissions.

should be distributed in each rule amendment is affected by the BARCT identified, the distribution of RTCs in the market, and staff's analysis on how best to implement BARCT.

For the proposed rule amendment, staff identified the new BARCT applicable for 20 major facilities (9 refineries and 11 non-refineries) and recommended shaving 56 facilities that hold 90% of the NOx RTCs and contributed 86% of the emissions. Staff proposed not to shave the remaining 219 facilities that hold only 10% of the NOx RTCs to keep them in the market.

Regarding the different shave percentages for the refinery sector and the non-refinery sector, staff estimated that by implementing BARCT the refinery and non-refinery sector could reduce 6.00 tpd and 2.77 tpd, respectively. Therefore, staff proposed shaving the RTC holdings from the refinery sector at a higher rate than the non-refinery sector weighted by the emission reductions that could be achieved. Staff proposed to shave the refinery sector by 66% and the non-refinery sector by 47%. The non-uniform shave is to ensure that the facilities subject to BARCT would install BARCT. After a shave of 22.5% "across-the-board" in 2005, the refineries opted to buy unused RTCs and not install any SCRs to reduce NOx emissions even though staff had estimated it was feasible and cost-effective for the refineries to install 51 SCRs by 2011.

In this case, if the percent shave were set at the same amount "across-the-board", facilities that do not have available BARCT, or where BARCT technology does not achieve the uniform 53% reduction, would have to purchase more RTCs from the refineries that can achieve 66% reduction. This would result in a redistribution of wealth from the non-refinery sectors to refineries. While this occurs to some extent under the staff proposal, the effect would be greatly increased.

For CEQA and socioeconomic analyses, staff considered five alternative approaches to allocate the RTC reductions. All five alternatives have "across-the-board" shave. The challenge of the RECLAIM program is to find the most appropriate shave distribution to protect the environment, attain the NAAQS, satisfy state and federal CAA requirements and AQMP commitments, and at the same time, allow for economic growth, provide equity, and safeguards for the functioning of the RECLAIM program.

With respect to the implementation time, because the implementation date for 2 tpd reductions in Phase 1 was due in 2014 and there are 5-8 tpd surplus RTCs in the market, staff believes that at a minimum 2 tpd reduction or up to 4 tpd reduction should be removed from the market no later than 2016, not "back-loaded" to 2019 as the commenter suggested. As explained in Response 1-2, the removal of unused RTCs is expected to raise the RTC prices and stimulate the implementation of control equipment. It is urgent to implement the control equipment and reduce actual emissions as expeditiously as possible to meet the NAAQS for PM2.5 and ozone.

Staff has planned for a sufficient lead time of approximately 2-3 years for the procurement, planning and engineering of BARCT. Except for the retrofits of Refinery 1's gas turbines scheduled in 2018, staff currently estimated that other retrofits would occur in 2019-2022 consistent with the commenter's recommendation. Staff has estimated that Refinery 1's gas turbines would be retrofitted in 2018 because the units have turnaround scheduled annually. This estimated schedule is used in the socioeconomic analysis with an assumption that the unused RTCs will be removed from the market early.

Response 1-4 Useful Life of Control Equipment

In the cost analysis for the proposed NOx RECLAIM amendment, staff has used a 25-year useful life for SCRs, LoTOx/scrubbers, and UltraCat applications. The commenter suggested that staff should have used a 10-year life since rule amendment is likely to occur in a 10-year interval (e.g. previous NOx RECLAIM amendment in 2005) and thus a 25-year life assumption makes the rule costs appear lower that they actually are by diluting the significant capital costs of required projects over a much longer time table than is likely to occur.

Staff used a 25-year life to be consistent with the following facts: [17]

1) The actual profile of SCRs in the SCAQMD: 27% of the refinery combustion equipment in the Basin has SCRs installed more than 25 years ago, and 63% of the refinery combustion equipment has SCRs installed more than 20 years ago. These units are still in operation and thus support the assumption of a 25-year useful life in the cost analysis.

2) Other air districts' staff has used similar assumption for control equipment life in their cost analysis: a) Some SCRs for refinery heaters in the Bay Area were installed in 1984 and thus the Bay Area air district staff uses a 20-year useful life in rule development. b) The SCRs in the Santa Barbara air district were installed in 1980-1990's and are still in good operating conditions, and thus the Santa Barbara air district staff supports a 25-year useful life of control device. c) Staff found several BACT analyses for the air districts in Florida that used 20- or 25-year useful life for SCRs.

3) The EPA OAQPS Costs Guidelines use a 20-year life for control equipment such as SCRs in their cost analysis.

4) Air pollution control manufacturers that staff contacted indicated that 20- or 25-year life is a reasonable assumption for control device such as SCRs, scrubbers, or LoTOx applications.

---

[17] Presented at the April 29, 2015 Working Group Meeting.

The commenter is concerned that a future RECLAIM amendment may require removal of equipment installed to meet the 2015 shave, so that the actual useful life is less than 25 years. This hypothetical has not been borne out by past experience. Even though the RECLAIM amendment was revised in 2005 and staff had estimated that the refineries would have to install 51 SCRs for refinery boilers/heaters by 2011, only 4 of these boilers/heaters were retrofitted with SCRs in responses to the EPA consent degrees or order of abatement. None of the SCRs were installed in responses to the 2005 BARCT assessment. Staff 2015 BARCT analysis did not identify any control equipment that would need to be removed in order to comply with the 2015 BARCT.

Furthermore, BARCT requirements were not revised in 2005 for refinery gas turbines, refinery SRU/TGTUs, refinery boilers/heaters >40 – 110 mmbtu/hr, glass melting furnaces, cement kilns and ICEs, thus the time interval between the BARCT assessments for these units is actually 22 years counting from the inception of the RECLAIM program in 1993. Adding several years allowed for planning, engineering, permitting, construction, and procurement of control equipment, the total time interval between installations of control equipment would be about 25 years.

The commenter implied that CARB may use a 10-year life for control devices. SCRs or scrubbers for major stationary sources are more durable than catalytic filters for mobile sources. CARB may use a 10-year life in their cost analysis for mobile source rules; however staff has consistently used a longer life when applicable in the cost analysis for major stationary sources: 1) a 25-year life was used in the cost analysis for electrostatic precipitators to control particulate emissions from FCCUs in Rule 1105.1; 2) a 20-year life was used for domes for refinery storage tanks in Rule 1178; 3) a 25-year life was used for SCRs in the 2005 NOx RECLAIM amendment; 4) a 25-year life was used for scrubbers in the 2010 SOx RECLAIM amendment; and 5) a 20- to 25-year life was used in Rule 1111. For other rules and regulations such as Rule 1146.1 and Rule 1147 that addressed low NOx burners, staff may use less than 25-year life depending on the type of control equipment and stationary sources. Finally, the commenter's concern can be addressed in any future RECLAIM amendment. In the event that the Board amends the rules in the near future to render obsolete any control equipment added, staff would add those stranded costs to the cost of that future amendment or consider a longer compliance schedule to maximize the useful life of the control equipment as much as possible.

Response 1-5 BARCT Analysis

In its comment letter electronically delivered on August 21, 2015, the Western States Petroleum Association (WSPA) claimed that "[…] RECLAIM must achieve emission reductions equivalent to or greater than traditional command and control, or BARCT. Thus, a NOx shave equivalent to BARCT (which the District proposes at 8.77 tpd) would be the level for comparison with the Health and Safety Code provision stating that equivalent or greater reductions would be achieved at `equivalent or less cost compared with current command and control regulations and future air quality measures that would otherwise have been adopted as part of the District's plan for attainment.' Yet, SCAQMD does not seek merely its determined BARCT equivalency level of 8.77 tpd; it seeks 14 tpd of NOx reductions and has not demonstrated that such reductions will be achieved at equivalent or lower cost than BARCT. The additional 5.21 tpd reduction goes above and beyond BARCT. […]"

1) **Removing 8.77 tpd of NOx RTCs would not result in the BARCT-equivalent level of actual NOx emission reductions:** BARCT requires *actual* emission reductions. The 2015 BARCT analysis demonstrated that there would be an actual NOx emission reduction of 8.77 tpd from the 2011-2012 activity levels at 2015 BARCT compared to the same activity levels at 2005 BARCT. This represents 8.77 tpd reductions in actual emissions. If the overall NOx RTC holdings had closely matched the total amount of actual NOx emissions from the NOx universe, the removal of 8.77 tpd of NOx RTCs would likely induce an equivalent amount of actual NOx emission reductions. However, over the past five years, actual NOx emissions from RECLAIM facilities fell below the overall NOx RTC holdings by 21-30%, resulting in approximately 5.45-8.41 tpd of unused NOx RTCs (unused for compliance purposes). Therefore, the removal of 8.77 tpd of NOx RTCs would first eliminate some, if not all, of these unused NOx RTCs from the market and only thereafter result in actual emissions reductions. Therefore, total emission reductions would be less than the BARCT-equivalent level of actual NOx emission reductions. The problem of excess unused RTCs is illustrated by the fact that the 2005 NOx shave did not achieve 2005 BARCT levels for the RECLAIM universe. The 7.7 tpd of NOx shave adopted in the 2005 RECLAIM amendments was phased in over the period of 2007-2011; however, only about 4 tpd of actual NOx emission reductions occurred between 2006 (the year before the 2005 shave began) and 2012 (the year after the 2005 shave was fully phased in). Almost two-thirds of the actual emission reductions resulted from facility shutdowns, not installation of controls or other changes at RECLAIM facilities. Therefore, as long as there are persistently unused RTCs available in the market, the RTC shave would need to be larger than the tons of emission reductions calculated for the BARCT analysis to induce an equivalent level of actual emission reductions. The proposed phased-in shave of 14 tpd is anticipated to be able to induce sufficient emission reductions by 2023 so that the expected total NOx emissions from the RECLAIM universe in 2023 would be consistent with the projected NOx emissions in 2023 at the 2015 BARCT levels. (Please see the Staff Report for the shave methodology.)

   In summary, staff disagrees with WSPA's comment that the proposed phased-in shave of 14 tpd would go "above and beyond BARCT."

2) **Installation of pollution control equipment is just one of the compliance options and the estimated control installation costs may not be fully incurred to achieve the BARCT-equivalent level of actual NOx emission reductions:** Unlike the traditional command-and-control regulations that typically requires the installation of pollution control equipment on all

emission sources, a RECLAIM facility has the flexibility of using RTCs to offset its facility-wide emissions and is expected to do so whenever it is the least costly option. Since the 1970s, economic research has demonstrated, both theoretically and empirically, that the compliance flexibility offered by such cap-and-trade programs generates cost-savings (e.g., Tietenberg 1990; Chan et al. 2012).[18]

The major source of the cost-savings under any cap-and-trade program is the differential in each market participant's ability to cost effectively reduce emissions. For a facility that can more cost-effectively reduce emissions, it benefits from the sale of surplus emission credits to offset pollution control installation costs; whereas for a facility that finds actual emission reductions too costly, it buys emission credits to account for the emission reductions that can be more cost-effectively achieved elsewhere. Therefore, emission credit prices in a well-functioning market must lie in between the upper and lower bounds of cost per ton of emission reductions among all market participants. If there is a large oversupply of emission credits and the market price ends up too low, there will be little incentive for facilities to implement any actual emission reductions.

A RECLAIM facility is expected to retrofit an emission source only when it meets both of the following conditions: first, it does not hold sufficient RTCs to offset facility-wide emissions at the end of the compliance period; second, the cost of control installation per ton of emission reduction is lower than the expected average RTC price over the life of the control equipment. Even if a facility finds it more cost-effective to install pollution control equipment, it still would not incur the full cost of control installation if control installation results in surplus RTCs that the facility eventually sells to offset the control installation cost. In comparison, command-and-control regulations would require, under all circumstances, that this same facility install the control equipment and incur the full cost of control installation. As a result, total costs to install controls under RECLAIM will always be equal to or less than under command and control. Under command and control, each facility must install the required controls, whereas under RECLAIM, the highest cost option is where each facility installs BARCT controls, because the total actual costs may be lower if a facility identifies any other more cost-effective alternative to remain in compliance.

3) **California Health & Safety Code §39616 applies, if at all, to the entire RECLAIM program since adoption, and not to a single shave:** The WSPA comment letter interpreted

[18] Tietenberg, Thomas H. 1990. "Economic Instruments for Environmental Regulation." *Oxford Review of Economic Policy*. 6 (1): 17-33. Chan, Gabriel, Robert Stavins, Robert Stowe, and Richard Sweeney. 2012. "The SO2 Allowance Trading System and the Clean Air Act Amendments of 1990: Reflections on Twenty Years of Policy Innovation." Cambridge, Mass.: Harvard Environmental Economics Program.

that H&SC §39616 applies to the adoption of RECLAIM and also separately to each of the subsequent amendments. Staff disagrees with this interpretation. H&SC §39616 (c) specifies that: "In adopting rules and regulations to implement a market-based incentive program, a district board shall, at the time that the rules and regulations are adopted, make express findings." One of those findings pursuant to H&SC §39616 (c)(1) is that emission reduction benefits and the costs of the program shall be compared with those of "current command and control regulations and future air quality measures that would otherwise have been adopted as part of the district's plan for attainment." H&SC §39616 (c) does not refer to "amendments". Nevertheless, assuming that the finding needed to continue to be made upon amendment of the rules, it makes sense to make that finding with respect to the entirety of the RECLAIM program since its adoption because the statute repeatedly refers to "the program" in specifying findings that need to be made. Thus, the structure of H&SC §39616 is directed to the program as a whole, which includes the entirety of the program since its adoption. With the exception of the 2000-2001 period when the California energy crisis took place, the historical discrete NOx RTC prices ($5,500 or lower per ton) have consistently been at the lower end of or below the cost-effectiveness range of pollution controls. As a result, many RECLAIM facilities have accrued substantial cost-savings over the years by being able to delay or forego the installation of pollution control equipment that would have been required at different points in time by command-and-control regulations. And even if the H&SC §39616 (c)(1) finding needs to be made for this proposed shave alone, the proposed shave is expected to only reduce the future stream of this cost-savings. Even so, a reduced cost-saving is still a cost-savings compared to command-and-control regulations. Thus, this amendment will clearly not cost more than the projected cost of command and control.

Staff acknowledges that, for a portion of the smaller emitters that have no cost-effective controls identified so far, they may have been affected by past RTC price spikes and could potentially be impacted by any future price fluctuations, either due to their RTC holdings or their limited financial capacity to hedge against price volatilities. However, their potential losses would be at the same time economic gains for the RTC sellers; therefore, the resulting net cost, if any, is expected to be zero or negligible to the entire RECLAIM program, particularly compared with the program's cost savings. While individual facilities may experience different costs and savings, H&SC §39616 applies to the RECLAIM universe as a whole.

It is misleading to separate the proposed NOx RTC shave into 8.77 tpd and 5.21 tpd and to argue that the 5.21 tpd shave of excess unused RTCs goes beyond BARCT, because BARCT is defined as the maximum degree of emissions reductions achievable (H&SC § 40406), and a shave of 14 tpd from current RTC levels of 26.51 tpd is necessary to attain the 12.51 tpd (26.51 tpd – 14 tpd = 12.51 tpd) of remaining NOx emissions in 2023, which staff analysis shows can be achieved with 2015 BARCT, after making allowances for growth, a compliance margin, and uncertainties that arose in the BARCT analysis. As a result, the 14 tpd shave does not go beyond BARCT. For the same reason, it is a distorted assertion that the estimated full control installation cost of $0.62-1.09 billion should be attributed to 8.77 tpd of NOx RTC shave only, with additional costs allegedly attributable to shaving the 5.21 tons of excess unused RTCs. This cost was estimated for *actual* NOx emission reductions of 8.77 tpd under command-and-control regulations, and it serves as the most conservative (i.e., maximum) estimate of the overall compliance cost for the proposed NOx shave of 14 tpd that will be needed to achieve the BARCT-equivalent level of NOx emission reductions. As noted above, costs to RTC buyers are offset by gains to RTC sellers so that this factor does not increase costs to the RECLAIM universe. The claim that costs should include the "value" of shaved RTCs is addressed below.

In the 2005 RECLAIM amendments, some stakeholders commented that the shaved RTCs would result in real, significant financial cost to companies and should be recognized as a cost. However, staff disagreed at the time RECLAIM was first adopted and still disagrees today. Staff has never considered the "cost" of the shaved RTC's to be recognized as a "cost" for determining equivalency with command and control. At the outset of RECLAIM, RTCs were allocated to RECLAIM facilities free of charge, yet they now have value to the facilities as a commodity that can be bought and sold. While RTCs have value, they are not a property right. The proposed amendments to RECLAIM will reduce the number of RTCs. Since there was no cost associated with allocated RTCs for a facility, there should be no financial loss to the RECLAIM universe as the SCAQMD retires them. Any additional purchase of RTCs executed by a facility is made in lieu of emission control. The choice between the RTC purchase and emission control is solely a business decision that is made to generate an expected stream of cost-savings afforded only by the RECLAIM program and not available under command-and-control. Therefore, any RTC investment loss should not be considered as a compliance cost to be compared to the compliance cost under command-and-control regulations. Moreover, this loss may be offset by any potential increase in RTC price due to a decreased RTC supply, which would subsequently raise the market value of a facility's remaining RTC holdings. Finally, any loss of "value" of shaved RTCs cannot be compared to command and control, because in that case, there are no RTCs and thus no similar "value" was ever created.

4) **Many unused RTCs are the result of shutdown selloffs, which have caused undue delay of BARCT-equivalent level of actual NOx emission reductions:** According to staff analysis of the RECLAIM transaction records, many of the unused RTCs were sold, as Infinite-Year-Blocks (IYBs), to operating RECLAIM facilities by some of the now-closed facilities prior to facility closure. These excess RTCs have been artificially depressing RTC prices and have induced RECLAIM facilities to delay the installation of cost-effective controls. A case in point is the 2005 NOx RECLAIM amendments. Despite 7.7 tpd of NOx RTC shave being implemented over the period of 2007-2011, only 4 tpd of actual NOx emission reductions had occurred by the end of the 2012 Compliance Year. Some of the 4 tpd of actual reductions came

from operational changes at refineries, which chose to run gas turbines instead of higher-emitting boilers at various points in time. However, just less than two thirds of the 4 tpd actual reductions were due to facility shut-downs and not measures taken to reduce actual emissions by facilities in the program. In 2005, the shave amount was partially based on the BARCT analysis that included the installation of 51 SCR units at refineries. However, not one has been installed due to the RECLAIM program. (Four SCR units were installed only due to orders for abatement.) While that choice did not violate RECLAIM, it resulted in facilities not achieving the level of emissions they would have achieved had they applied BARCT. As a result, there is a need to ensure that the currently proposed shave is sufficient to induce emission reductions equivalent to 2015 BARCT levels, accounting for growth to 2023.

The original intent of RECLAIM, or any cap-and-trade program, is for all participating facilities to benefit from the differential in each operating facility's ability to cost effectively reduce emissions. It is not to shift a closed facility's prior pollution credits to any facility still in operation and cause undue delay of BARCT-equivalent level of actual NOx emission reductions. (Under command-and-control, any pollution credits from a shut-down facility would at least be discounted by BACT.) As a result, staff proposes this level of BARCT-based shave to substantially reduce the amount of unused RTC credits in the market in order to better ensure the timely implementation of BARCT as required under state law.

Response 1-6 NEC Study

Staff disagrees with the commenter's suggestion that the BARCT cost analysis for the refinery sector needs to be revised to explicitly consider the findings presented by the Norton Engineering Consultants (NEC). First of all staff and NEC both obtained the same average cost effectiveness for refineries. Table 6.1.6 summarized the differences in staff's and NEC's findings in each category of sources:

Total difference in emission reductions: 6.00 tpd (staff) – 5.67 tpd (NEC) = 0.33 tpd
Total difference in PWVs: $629 million (staff) - $562 million (NEC) = $67 million
No difference in average cost-effectiveness for refineries = $11 K per ton (NEC and staff).

Secondly, staff has reduced the proposed shave by 0.85 tpd to more than account for the difference in 0.35 tpd shown above and provide additional compliance margin. The cost-effectiveness value of $11 K per ton estimated by both NEC and staff is lower than the estimated $16 K per ton for the Control Measure CMB-01 in the 2012 AQMP. [19]

The difference between the two analyses occurs in the category of boilers/heaters. Staff's estimates resulted in 0.33 tpd more emission reductions because 35 more heaters that were considered cost-effective compared to NEC's estimates because NEC and staff used different cost

[19] Page IV-A-58, Appendix IV-A, and Table 6-4 of 2012 AQMP.

data to estimate cost. Staff believes its proposal was reasonable since its approach utilized information in the facility permits, information provided by the refineries through the Survey, and information provided by several prominent manufacturers of control devices for each specific category of sources. NEC used a verbal quote for one FCCU SCR to derive the costs for FCCUs, boilers/heaters and SRU/TG applications. The SCR catalysts for FCCU are not the same as the catalysts for boilers/heaters and SRU/TG applications. Nevertheless, staff added 0.8 tpd to the remaining emissions (i.e. reduced the shave by 0.8 tpd) to allow for this difference. Further explanations are provided in Response 1-6 for FCCUs and Response 1-7 for boilers/heaters.

Table Z.1-6 – Differences in Staff's and NEC's Findings

Category	Proposed BARCT	Emission Reductions	Cost Effective Units	PWVs	Incremental Cost Effectiveness DCF (note 1)	Conclusion
Boilers and Heaters with SCRs	No difference 2 ppm	Staff = 0.94 tpd NEC = 0.61tpd Diff. = 0.33 tpd	Staff = 83 units NEC = 48 units Diff. = 35 units	Staff = $242M NEC = $162M	Staff = $28K/ton NEC = $29K/ton	0.85 tpd shave reductions (note 2)
FCCUs with SCRs	No difference 2 ppmv	No difference 0.43 tpd	No difference 5 FCCUs (note 3)	Staff = $152M NEC = $211M (note 3)	Staff = $18K/ton NEC = $25K/ton	No difference
SRU/TGTUs with SCRs	No difference 2 ppmv	No difference 0.32	No difference 9 SRU/TGTUs	Staff = $83M NEC = $96M	Staff = $28K/ton NEC = $33K/ton	No difference
Gas Turbines with SCRs	No difference 2 ppmv	No difference 4.14 tpd	No difference 11 gas turbines	Staff = $98M NEC = $53M	Staff = $3K/ton NEC = $1K/ton	No difference
Coke Calciner with LoTOx	No difference 10 ppmv	No difference 0.17 tpd	No difference 1 coke calciner	Staff =$54M NEC =$39.5M	Staff = $35K/ton NEC = $25K/ton	No difference
Total		**Staff = 6.00 tpd NEC = 5.67 tpd**	**Diff. = 35 heaters**	**Staff = $629M NEC = $562M**	**Staff = $11K/ton NEC = $11K/ton**	**0.85 tpd shave reductions (note 2)**

Note: 1) Ratio LCF/DCF = 1.6, e.g. $1K/ton DCF = $1.6K/ton LCF. 2) Staff provided 0.85 tpd reductions in shave to account for uncertainties in cost analysis assumptions for boilers/heaters and additional compliance margin. 3) Refinery 4 FCCU is scheduled to be shut-down in 2017-2018 which would result in lowering the costs estimated for this category.

As shown in this table, except for boilers/heaters, the same equipment was identified as cost-effective regardless of whether NEC costs or staff estimated costs were used, so there is no difference in calculated BARCT emission reductions. In the socioeconomic report, staff used the high end of the total costs.

Response 1-7 NEC Study for Boilers/Heaters

WSPA sasserts that because only a few boilers and heaters are currently equipped with SCR are currently meeting 2 ppmv NOx, this level cannot be BARCT.

NOx Feasible Level

First, it is important to note that staff is obligated to find technology that can reduce maximum amount of pollution to help the basin achieve the ozone and PM2.5 standards and meet the requirement sated in H&SC §40406:

> "*... an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, & economic impacts by each class or category of source*."

The two criteria required to be considered for BARCT are 1) technologically feasible and 2) cost-effective. The feasible and cost-effective control technology must be considered BARCT even if they are not yet operational in the District. In this case, WSPA admits that some units are currently achieving 2 ppmv which is strong evidence that this level is achievable. Staff is not required to focus only on achieved-in-practice and fully commercialized control technology (i.e. technology that is either being offered commercially by vendors or is in commercial demonstration or licensing)[20]. Staff can use a control technology that has been previously installed and operated successfully at a similar type of source, or has potential for application to the source (i.e. has been successfully applied to similar sources with similar gas stream characteristics). For boilers/heaters category, staff included the analysis for SCRs as well as Great Southern Flameless and ClearSign as shown in Appendix B of the PDRS.

Contrary to the commenter's understanding, the H&SC does not specify any threshold on the number of units that must be proven achieved-in-practice for a control technology to be considered feasible. [21]As an example, in the 2010 SOx RECLAIM amendment, staff assessed and determined that a level of 10 ppmv SOx was feasible and cost-effective for a sulfuric acid plant using wet gas scrubber technology even though there was no sulfuric acid plant that had yet achieved this level. The sulfuric acid plant installed a wet gas scrubber in 2011 after the rule was amended, source-tested the unit, and demonstrated that the unit met a level much less than 10 ppmv.

Regarding the count of boilers/heaters, based on information received from the refinery Survey, 14 heaters using refinery fuel gas were reported to achieve 1.6 - 3.5 ppmv NOx with SCRs (Table B.3 of Appendix B). Four of the 14 heaters were reported to achieve 1.6 ppmv NOx. The heaters' maximum ratings are 88, 125, 177, and 199 mmbtu/hr. Based on information in the permit applications, three heaters were first installed in 1970, the fourth heater and the SCR were installed

---

[20] American Coatings Assoc. v. SCAQMD, 54 CAL. 4TH 446 (2013)

[21] American Coatings Assoc. v. SCAQMD, 54 CAL. 4TH 446 (2013)

in 1994. In 2004, all four heaters were modified to increase the overall heaters' capacities, and thus all 4 heaters were subject to a permit limit of 5 ppmv NOx. It should be noted that the SCR has been in operation for 21 years and still achieves a level below 2 ppmv NOx. Thus, it is reasonable for staff to consider 2 ppmv as a feasible BARCT level.

It seems that the WSPA/ERM's confidential survey in March 2015 reported different information than the information in the permits. It indicated that only 2 of the 4 heaters were retrofits and the remaining 2 heaters were new.

As stated above, besides SCRs, staff has also identified other control technologies that can potentially achieve 2 ppmv NOx level such as Great Southern Flameless, ClearSign, and LoTOx. A crude heater manufactured by Great Southern Flameless installed at the Coffeyville refinery in Kansas achieved 3-8 ppmv NOx without the use of SCR. Two boilers using natural gas equipped with LoTOx achieved 2-5 ppmv. ClearSign has recently signed a contract with Tesoro to retrofit a heater at Tesoro refinery and hopefully this project can be proven to achieve 2 ppmv NOx without the use of SCR. Great Southern Flameless, ClearSign, and several prominent SCR manufacturers provided staff the estimated costs of control equipment that can be designed to achieve 2 ppmv NOx.

Response 1-8 FCCUs

WSPA contents that staff should not set a BARCT level of 2 ppmv NOx for FCCUs because only one FCCU is currently achieving this level. Staff is required to find technology that can potentially reduce maximum amount of pollution to meet the requirement stated in the H&SC §40406 and help the basin achieve the NAAQS for ozone and PM2.5. Although staff recognizes that there are differences among different refineries, both staff analysis and NEC's analysis identified 2 ppmv as achievable BARCT for FCCUs.

Staff has evaluated two potential control technologies for FCCUs, SCRs as well as scrubber/LoTOx and estimated the cost-effectiveness values for both technologies to ensure that the control technologies were cost-effective. The SCR and LoTOx/scrubbers manufacturers confirmed that 2 ppmv is feasible and provided cost information for the cost analysis.

Each refinery may have unique circumstances (e.g. equipment type, age) and different upstream configuration, however the downstream control equipment such as LoTOx/scrubber and SCR can be designed to achieve the 2 ppmv level as confirmed by the manufacturers and agreed by NEC.

There is precedent in identifying controls based on achievements by a single FCCU at the time the rule adoption. For example, in previous rule development in the SCAQMD, only one FCCU had achieved the BARCT level of Rule 1105.1 at the time the rule was developed.[22] Likewise, only one FCCU in the Basin had achieved the BARCT level of 5 ppmv SOx at time the rule was amended in 2010.

Regarding SCR costs, staff estimated a range of $152 million (no markups) to $163 million (with two layers of markups used by NEC). NEC estimated $211 million (with different feed rates.) NEC's estimates were about 40% higher than staff's estimates. The SCRs were cost-effective at 2 ppmv using either NEC's or staff's estimates. The cost effectiveness for FCCU SCRs has a range of $18K/ton - $25 K/ton.

Response 1-9 Costs and Cost Effectiveness Analysis

This comment asserts that staff's BARCT analysis should be changed because NEC estimated higher costs for certain equipment.

Cost Effectiveness for Refinery Sector

The costs and cost-effectiveness values for each individual class or category of sources are summarized in Table 6.1.6. The overall weighted average cost-effectiveness for the refinery sector based on NEC's and staff's estimates is $11 K per ton DCF ($18 K per ton LCF) with SCR technology, which is well below the thresholds that the commenter cited for the BACT Guidelines and the 2012 AQMP.

Since RECLAIM achieves its reductions in the aggregate rather than based on individual equipment, it is appropriate to look at cost-effectiveness in the aggregate using total program costs and total program reductions.

This comment also asserts that staff should have used the LCF methodology. Staff used a threshold level of $50,000 per ton DCF to exclude individual equipment from the BARCT analysis to be consistent with the SOx RECLAIM amendment in 2010. The cost-effectiveness values based on DCF and LCF methods are not directly comparable to each other: DCF discounts all future operation and maintenance costs to their present values whereas LCF amortizes the initial capital and installation costs over the equipment lifetime. This is why DCF values are always lower than LCF values for the exact same amount of estimated compliance cost. Due to this methodological difference, staff disagrees with the commenter's claim that the same cost effectiveness threshold should be used for both DCF and LCF methods. If the threshold for DCF was $50,000 per ton, the threshold for LCF should be about $80,000 per ton.

---

[22] Rule 1105.1 – Reduction of PM10 and Ammonia Emissions From Fluid Catalytic Cracking Units, Adopted November 7, 2003.

Cost Effectiveness Thresholds in BACT Guidelines

The commenter cited a threshold in the BACT Guidelines of $19,100 per ton NOx reduced. It should be noted that this threshold was estimated in the 2nd quarter of 2003 and should be adjusted to $28,000 per ton as of 2015 dollars. The threshold considers the difference in costs and emissions between a proposed BACT and an uncontrolled case. The commenter however should cite the threshold for “incremental” cost effectiveness which looks at the difference in costs and emissions between a proposed BACT and a less stringent control level. The threshold for “incremental” cost effectiveness is $57,200 per ton as of 2nd quarter 2003 and should be adjusted to $80,000 per ton as of 2015 dollars. This is a more appropriate comparison when looking at two possible incrementally different levels of control.

More important, these thresholds are for equipment located at non-major polluting facilities (also known as minor sources BACT, or MSBACT, in Part C of the BACT Guidelines). There are no thresholds for sources located at major polluting facilities such as the refineries, BACT/LAER is required without any cost consideration for sources located at major polluting facilities (Part A and B of the BACT Guidelines).

Cost Effectiveness for Entire Proposed RECLAIM Project (Refinery and Non-Refinery)

This comment further asserts that RECLAIM facilities may be being treated disproportionately compared to facilities under command-and-control by having higher cost effectiveness. First of all, it is necessary to look at the RECLAIM program as a whole since H&S Code 39616 (c)(7) refers to “disproportionate impacts measured on an aggregate basis” on sources in RECALIM. As shown below, the cost effectiveness for the entire RECLAIM project, including refinery and non-refinery, ranges from $7K - $12K per ton.

The PWVs for the entire NOx RECLAIM project as shown in Tables 4.3 and 4.4 (w/o cement kilns):

Low end: $565 million (refinery) + $163 million (non-refinery) = $728 million
High end: $923 million (refinery) + $176 million (non-refinery) = $1099 million

Total emission reductions: 6.00 (refinery) + 2.77 (non-refinery) = 8.8 tpd

The overall range of cost-effectiveness for the entire RECLAIM project:

Low end of range: 728,000,000/8.8/25/365 = $9,066 per ton
High end of range: 1,099,000,000/8.8/25/365 = $13,686 per ton

Table Z.1-9 Cost Effectiveness Comparison

	Cost Effectiveness ($/ton)
Proposed Amendment	9,066 – 13,686
Control Measure CMB-01	7,950 (Phase I) – 16,000 (Phase II) [23]
Threshold in BACT Guidelines for "Minor Sources"	80,000 [24]
2012 AQMP	22,500 [25]

As shown in Table Z.1-9, the cost-effectiveness for this proposed NOx RECLAIM amendment is less than the thresholds that the commenter cited for the BACT Guidelines and the 2012 AQMP. They are also within the average cost effectiveness estimated for Control Measure CMB-01 in the 2012 AQMP.

Moreover, the NOx cost-effectiveness threshold of $22,500 proposed in the 2012 AQMP was intended as a threshold above which tiered levels of analysis would be conducted. It was not intended as a threshold above which a control measure would automatically be excluded. Therefore, this threshold should not be used to determine whether proposed rules or amendments would be cost effective.

In conclusion, it is conservative in using a threshold of $50,000 per ton for "incremental" cost effectiveness to eliminate cost-ineffective individual scenarios.

Response 1-10 Costs and Cost Effectiveness Analysis

This comment asserts that NEC conducted a comprehensive evaluation of site-specific factors for each refinery, which staff did not appropriately consider. However, staff has maximized the use of site specific information provided by NEC on installation, design, engineering costs, space needed, plant configuration, equipment type, equipment age, length of time for SCR to operate and remain in service, and time needed for construction.

As explained in response 1-6, in only one case did NEC reach a different conclusion than staff regarding the appropriate BARCT (boilers/heaters). For that category, staff removed the emission reductions associated with equipment that was cost-effective under staff's analysis but not under NEC's analysis from the BARCT reductions (0.33 tpd. In fact, staff actually removed 0.8 tpd from the proposed shave.) The socioeconomic report gives appropriate consideration to the higher end of total BARCT costs.

---

[23] Table 6-3 and 6-4 of the 2012 AQMP, and page IV-A-13 and page IV-A-58, Appendix IV-A of the 2012 AQMP
[24] "Incremental" cost effectiveness on page 29 of the SCAQMD BACT Guidelines, dated July 2006, adjusted to 2005 dollars
[25] Cited by the commenter, page 4-43 of the 2012 AQMP, February 2013

This commenter further asserts that staff did not properly consider installation, design, and engineering costs and that what is cost effective at one refinery may not be at another. Again, NEC confirmed, after visiting the sites, that staff's proposed BARCT was appropriate for all cases except refinery boilers/heaters, described above. Staff looks forward to receiving the additional information WSPA states that it will submit.

Response 1-11 Disproportionate Impacts

This comment asserts that RECLAIM facilities may be disproportionately impacted because non-RECLAIM facilities represent the majority of stationary source NOx emissions yet the District does not appear to be seeking reductions from them. The commenter also argues that reductions from non-RECLAIM sources must be "proportionate".

It is incorrect to assert that staff is not seeking reductions from non-RECLAIM sources. Staff is seeking emission reductions for all sources, RECLAIM and non-RECLAIM, where feasible and cost-effective control technologies are available to help the basin achieve the ozone and PM2.5 ambient air quality standard as expeditiously as possible.

Even though RECLAIM sources collectively account for 27 tpd NOx emissions while non-RECLAIM sources such as residential fuel combustion, waste disposal, and miscellaneous processes together account for 46 tpd, RECLAIM is the fourth largest source of NOx emissions in the Basin and the top #1 emitting stationary source. There is no requirement to reduce NOx emissions from all sources at the same time. Nor is there any requirement that all sources must reduce emissions "proportionately", i.e. by the same percentage.

Instead the law requires the District to seek BARCT-level reductions from all existing sources. BARCT is not a fixed percentage such as 40% or 50% reductions. Instead, it is defined as the maximum level of reductions achievable for each class or category of sources. For example, some equipment may be already relatively low-emitting so the maximum achievable reductions may be a smaller percentage, and some equipment may not have a cost-effective option available that will achieve the same percentage reduction as the RECLAIM sources. As long as each category implements the maximum reductions achievable for that category, there is no disproportionate impact.

Staff has continually sought BARCT NOx emission reductions from all sources, large and small. Recent examples include Rules 1110.2 (engines), 1146, and 1146.1 (boilers, heaters, steam generators) and Rule 1147 (miscellaneous NOx sources). The District has regulated sources as small as residential water heaters (Rule 1121).

Furthermore, the control technologies that can reduce emissions from RECLAIM sources are commercially available and some are achieved-in-practice whereas the control technologies for many non-RECLAIM sources are being developed and not yet identified in the 2012 AQMP.

In addition, the RECLAIM program offers many other benefits to the RECLAIM facilities which show that these sources are not suffering disproportionate impacts on an aggregate basis.

— *Source-specific standards.* The non-RECLAIM facilities are subject to source-specific standards (e.g. concentration limit or mass emission limit) and every source (e.g. boiler or heater) at the non-RECLAIM facilities must be controlled to the same concentration limit or mass emission limit, and the source-specific command-and-control limit cannot be exceeded at all times whereas the RECLAIM facilities can operate their equipment with flexibility, they can purchase RTCs from other RECLAIM facilities to reconcile the emissions with the facility caps at the end of the compliance year in lieu of installing control;

— *BACT Discount.* The emissions from shutdown equipment at the non-RECLAIM facilities are required to be discounted to the BACT level before ERCs can be issued whereas the RECLAIM facilities can use or trade the RTCs associated with shutdown equipment without any BACT discount;

— *NSR Offset Factor.* The new or modifying non-RECLAIM facilities undergoing New Source Review (NSR) are required to offset any NOx or SOx emission increase by a factor of 1.2 to 1.0 ratio whereas the RECLAIM facilities are not subject to this offset. Instead, the RECLAIM facilities are required to hold sufficient RTCs based on their maximum potential to emit at a ratio of 1.0:1.0 at the beginning of each compliance year, and they can sell back the unused RTC offset holdings at the end of each compliance year.

— *Flexibility to Install Control.* The RECLAIM facilities have the flexibility to install the least cost controls first, and have the flexibility to use the program averaging and cross-cycle trading to balance their compliance option.

— *Trading.* In addition, the RECLAIM facilities receive monetary benefits from trading their RTCs (equivalent to "Potential-to-Emit") for the past 22-year life of the RECLAIM program to reduce the costs of compliance.

Because of the many benefits available in the RECLAIM program, staff believes that the RECLAIM facilities are not being disproportionately impacted by participating in the program.

Response 1-12 Energy Efficiency Projects

In responses to question #10 of the Survey Questionnaire,[26] the refineries sent to staff the CARB's report released in June 2013.[27] Note that the actual emissions and the RTC holdings have different "currencies". It is very likely that the 2011 emissions baseline already reflects the energy efficiency projects (i.e. 0.7 tpd co-benefit reductions were included in the baseline.) However, The RTC holdings ("Potential to Emit") were last adjusted in 2005, and at that time, the energy efficiency projects were not yet been completed, thus the RTC holdings ("Potential to Emit") have not yet been reduced to reflect the energy efficiency projects. However, staff did not reduce the shave by 0.7 tpd to reflect the co-benefit reductions of the energy efficiency projects because this was used to offset the increase between the 2011 and 2012 emissions baseline for the refinery sector. The information on energy efficiency projects as part of the responses to the refinery Survey should be included in the PDSR.

Response 1-13 Socioeconomic Impacts

Staff is working on the socioeconomic report and the report will be made available soon.

Response 1-14 2012 Compliance Year Emissions Baseline

Staff used the 2011 compliance year emissions as baseline because 2011 is the last year for implementation of the 2005 NOx RECLAIM amendment. Staff estimated the shave based on the remaining emissions projected to the 2023 compliance year. If the compliance year 2011 emissions were used, the growth factor from 2011-2023 will be used to project the emissions to 2023. If the compliance year 2012 emissions, the growth factor from 2012-2023 will be used to project the remaining emissions. Both methods should result in the same 2023 remaining emissions for RECLAIM facilities assuming that the growth factors are projected reasonably accurate to reflect the change in emissions. For the refinery sector, staff used a [WW3][m4]growth 1.0 provided by the refineries since the inception of the RECLAIM program in 1993. The 2012 compliance year emissions are 0.6 tpd higher than the 2011 compliance year emissions, thus the 2023 remaining emissions would be 0.6 tpd higher for refinery sector. However, there are 0.6 tpd co-benefits associated with the energy efficiency projects that were not being taking out of the RTCs holdings in the 2015 NOx RECLAIM amendment which would wash out the effect of the change in baseline year.

[26] Appendix L of the PDSR

[27] Appendix K of the PDSR

Response 1-15 NEC's Cost Analysis

Refer to Responses 1-6, 1-7 and 1-10. On contrary to the commenter's remarks, staff strongly believes the approach used is consistent with the requirements in H&S Codes in evaluating and conducting a technical feasibility and cost-effectiveness analysis for the NOx RECLAIM project. Staff did not ignore NEC's findings. On the contrary, staff has maximized the use of NEC's site specific information on installation, engineering costs, space needed, plant configuration, equipment type, equipment age, length of time for SCR to operate and remain in service, and time needed for construction. Moreover, NEC reached the same conclusion as staff for BARCT for all refinery source categories except boilers/heaters. For that category, staff adjusted the BARCT goal by adding 0.8 tpd to the goal, which is more than enough to account for the emission reductions attributable to equipment that was not cost-effective under the NEC analysis.

Response 1-16 0.85 tpd for Uncertainties

Refer to Response 1-7. Staff believes that providing 0.8 tpd RTCs is sufficient to account for the uncertainties and differences in the analysis related to boilers/heaters which amount to only 0.33 tpd difference in emission reductions between staff's and NEC's analyses

Response 1-17 Regional NSR Holding Account for Non-Electric Generating Facilities

Staff has created a Regional NSR Holding Account to help facilities in the power sector subject to Rule 2005 NSR requirements. Staff has discussed this issue with the U.S. EPA to seek their approval on the concepts. Other facilities have more flexibility than Electric Generating Facilities to reduce their PTE and thus their required RTC holdings if their actual emissions are lower than their PTE.

Response 1-18 Compliance Margin

Refer to Response 1-2 for discussion on compliance margin. The cement plant was shutting down but staff still included 0.29 tpd for the remaining emissions of cement kilns and 0.1 tpd for the remaining emissions of other shutdown facilities. Since the cement plant and other shutdown facilities are not coming back in business, this amount of RTCs will serve as additional compliance margin to the entire NOx RECLAIM universe.

Response 1-19 Across-the-Board Shave

Refer to Responses 1-3.

Response 1-20 Emissions from 219 Facilities

Staff will revise the statement to state:

"The remaining 219 facilities that hold 10% of the 26.5 tpd RTC are not proposed to be shaved because there is was either no new BARCT for the types of equipment and operation at these facilities (e.g. these facilities do not have FCCUs, coke calciner), or limited amount of emission reductions that could be achieved (less than 0.1 tpd for ICEs and small boilers/heaters).

Response 1-21 Implementation Schedule

Staff believes that the amount of unused RTCs in the market can support 4 tpd early reductions in 2016, and extending one more year from 2022 to 2023 may not be necessary.

Response 1-22 Longer Public Participation

Staff has been conducted public meetings on the proposed NOx RECLAIM for almost 3 years, and staff is planning for a public hearing in November 2015. The CEQA and socioeconomic analyses would be released for public comments according to the requirements in the H&SC §40440.5.

Response 1-23 Energy Efficiency Projects

Refer to Response 1-12.

Response 1-24 CEQA Alternatives

The size of the shave to represent 3-5 tpd of Control Measure CMB-01 of the 2012 AQMP would be about 11% - 19%, between the "No Project" Alternative (0% shave for Alternative 4) and the "Industry Proposal" Alternative (33% shave for Alternative 3).

Response 1-25 Cost Analysis

Please refer to Responses 1-5, 1-9, and 1-10.

Response 1-26 Useful Life 25 Years
Refer to Response 1-4.

Response 1-27 DCF versus LCF Cost Effectiveness

Refer to Response 1-9.

Response 1-28 Reductions and Remaining Emissions

Refer to Response 1-2 for the response addressing remaining emissions, Control Measure CMB-01, shave methodology, and the necessity to seek for more than 5 tpd reductions as estimated in Control Measure CMB-01. Refer to Response 1-11 for the response addressing disproportionate impacts. Refer to Responses 1-5 for the response addressing H&S Code 39616 requirements.

Response 1-29 Compliance Margin

Refer to Response 1-2. In addition, WSPA's comment admits that the program has functioned on as little as 15% compliance margin, and has not shown any need for the much longer amount of excess RTCs allowed by the industry's proposal.

Response 1-30 Remaining Emissions for Refinery Sector

Refer to Responses 1-6 and 1-7. NEC identified the same BARCT for all refinery categories except boilers/heaters. Staff provided 0.8 tpd reductions in shave to account for comments received from stakeholders regarding uncertainties in the BARCT analysis and thus provide additional compliance margin. Staff is required to show incremental cost effectiveness for the entire category of source and not for individual equipment. Thus, incremental emission reductions = 0.43 tpd (incremental emissions from 2005 BARCT) and incremental PWVs = $152 - $391 million for the FCCU category.

Response 1-31 Appendix A - FCCUs

Refer to Response 1-6.

Response 1-32 Appendix B – 2 ppmv Level for Boilers/Heaters

Refer to Response 1-7. The count of boilers/heaters presented at the September 19, 2013 Working Group Meeting (9 heaters having NOx emissions between 1.6 – 5 ppmv) was updated at a later date. The updated list in the PDSR showed 14 heaters with NOx emissions between 1.6 – 3.5 ppmv. Furthermore, the level of 2 ppmv not 3.5 ppmv should be considered as BARCT since it is "*…an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy & economic impacts by each class or category of source*".

Response 1-33 Appendix B – NEC's Analysis for Boilers/Heaters

Refer to Response 1-7. Several heaters have already achieved this level presenting strong evidence that it is achievable. The difference in emission reductions between the two estimates was only 0.35 tpd and staff provided 0.85 tpd reductions in RTC shave to account for uncertainties in the assumptions of the cost analysis and additional compliance margin.

Response 1-34 Appendix B – Cost Analysis for Boilers/Heaters

Staff does not understand the comment. The "programmatic" overall average cost effectiveness for boilers/heaters category is $27,529 ton NOx reduced as shown in Table B.11, page 77 and Table 4.3. Refer to Table 6.1-6 for comparison between NEC's and staff's estimates. Also, refer to Response 1-7.

Response 1-35 Appendix D – Coke Calciner

This comment supports staff recommended BARCT for this category. No response is needed.

Response 1-36 Appendix E – SRU/TGs Applications

NEC's cost analysis does not alter the BARCT conclusion for SRU/TG applications. There were no differences in emission reductions between the two estimates. NEC's estimates of costs were 16% higher than staff's estimates. SCRs were cost-effective with NEC's and staff's estimates of costs. See Table 6.1-6.

Response 1-37 Appendix K – Energy Efficiency Projects
Refer to Response 1-12

Response 1-38 Shave Approach
Refer to Response 1-3.

Comment Letter #2 – NEC's Letter Dated August 10, 2015

Comment 2-1 FCCU SCR Costs

NEC stated that they agreed that 2 ppmvd (3% O_2) NOx emissions is a justifiable emission level for SCR applications to FCCUs, Fired Heaters, Boilers, Gas Turbines and TGU/SRUs, with caveats….. NEC believed that it is possible to achieve these levels, but to guarantee long term reliable performance (refineries typically operate 24/7 for periods of 4 to 6 years) it is prudent and quite possibly necessary to design future SCRs to increase residence time, improve NH_3 distribution, improve overall flue gas flow distribution, add catalyst, etc. SCAQMD staff agrees with this concept but NEC and staff have strong disagreement as to how much change from current SCR designs will be required to achieve the sought after NOx reductions not only on day one but at the end of year one and year five and beyond.

Response 2-1

Staff concurs that there may need to be a change from current SCR designs in order to achieve the 2 ppmv. As presented in the Preliminary Draft Staff Report (PDSR), the SCR profile for the refinery FCCU SCRs currently installed relies on 2-layers of catalyst. The NEC model is scaled to operate using 3-catalyst layers. This merely reflects a difference in engineering approach. NEC is arguing that the third bed is needed for reliability, however Refinery 1 has operated their FCCU SCR with two beds of catalysts and achieved less than 2 ppmv NOx since 2003 and several manufacturers provided costs based on SCR applications using a 2-layer catalyst bed that meet the proposed 2 ppmv BARCT emissions level, thus staff believes that 2 layers of catalysts are sufficient. The NEC model is not based on or proposed for a specific SCR application, but instead provides a configuration that will achieve the same reductions. The resulting technical specifications between the two approaches are different, whereby the SCR box size, catalyst volume, and layer configuration, among other aspects of installation, account for the difference in cost estimates. However, the potential additional cost to enhance SCR designs does not impact the total proposed reduction in RTC holdings.

Comment 2-2 Basis for Catalyst Addition and Velocity Reductions vs Vendor Budget Quotes

All FCCU SCR catalyst beds are in the range of 3 - 4' deep, all are prone to plugging by catalyst and/or ABS and all have limitations on allowable pressure drop, so superficial velocity is a good basis for comparison between units. The district has three operating FCCU SCRs. All units have two catalyst beds and operate at superficial gas velocities in the range of 8 to 13 ft/sec. Two of the three units, operating at superficial velocities of 12 and 13 ft/sec do not achieve emissions of 2 vppm @ 3% O_2. The other unit, highlighted in the draft report, achieves less than 2 vppm @ 3% O_2 operating at a superficial velocity of 7.7 ft/sec. The "good" unit is operating with inlet NOx levels which are 50% of design or lower and at lower than design flue gas flows. There are several ways to bring the two "non-performing" units into compliance with the revised standard, each with different costs and different overall performance impacts. NEC was not commissioned to do an evaluation of individual units and propose improvement options, but rather to make an assessment of what it would take, cost wise, to reliably achieve the 2 ppmv limit for grass roots SCR installations. Based on the experience of operating units in the district, and our direct experience with FCCU units for other clients (due to confidentiality agreements we cannot divulge client identities and specific locations) reliably achieving 2 vppm NOx emissions in an FCCU over a five year run will require the addition of catalyst and will be designed for superficial velocities of 10 ft/sec or less. Considering that SCR catalyst vendors have not developed and guaranteed a specific SCR design for 2 ppmvd @ 3% O_2 NEC feels that it is prudent to assume that a third bed of catalyst (SCR or ASC) and cross section designed to achieve a maximum superficial velocity of 10 ft/sec is sufficient to characterize the most likely cost of a SCR unit capable of achieving 2 ppmvd in a typical refinery FCCU environment. The impact of the increased cross sectional area and the addition of a third bed of catalyst on the cost of an SCR installation has been overstated by district staff as a 284% increase in catalyst volume over manufacturer's estimates. The increase over manufacturer's budget estimates/proposals is actually 92%, one half of staff's reported delta.

Response 2-2

Staff understands the reasoning behind NEC's methodology in determining the impact of the increased cross sectional area and the addition of a third bed of catalyst on the cost of an SCR installation. A review of Item 1 on page 121 of the PDSR indicated that the "total catalyst volume" was incorrectly stated and should have read "total SCR volume." and was followed by an incorrect projected catalyst volume and space velocity. It is important to note that the NEC reports did not directly state the height of the catalyst layer within each SCR layer but referred to the SCR layer as 11 ft. Correspondence with NECs staff indicated that the catalyst layer height would be less than 55% of the SCR layer height and subsequent conversations with NEC projected the catalyst layer height within the range specified above. The uncertainty in the catalyst layer height may have contributed to the incorrect calculation of catalyst volume presented in the PDSR assessment in Appendix F. We concur that the increase over manufacturer's budget estimates/proposals is approximately 92 percent and the next version of the staff report will corrected.

Comment 2-3 Staff's SCR Design Comparison Did Not Accurately Reflect NEC's "Typical" FCCU SCR Design

Staff used an incorrect basis for comparing NEC's typical FCCU SCR with district units in Table F.3. A revised comparison, using data from Refineries 1, 5 and 6 is shown below.

Table 1 (F. 3 Showing NEC Typical SCR)
Performance Information of Existing SCRs

	Refinery 1	Refinery 5	Refinery 6	NEC Typical
FCC Feed Rate, kBPD	95	71	84	55
SCR Inlet Flue Gas Flow, ACFS	6,585	5,525	9,685	3,848
SCR Manufacturer	1	3	2	--
No. Catalyst Layers	2	2	2	3
Catalyst Volume, ft^3	6,200	2,975(1)	6,200(5)	4,600
Design Inlet NOx, ppmv	133(2)/40-80(3)	150	35	45
Design Outlet NOx, ppmvd	--	17	6	2
NOx Measured, ppmvd	<2	15-17	5.6 – 6.4	1.5 (Est.)
Superficial Gas Velocity, fps	7.4	13.3	11.6	10.0
Space Velocity, 1/hr	3,823(6)	6,686(4)	5,624(5)	3,011
Removal Efficiency	95 - 97%(3)	89%	83%	97%

Notes:
1. Staff incorrectly stated catalyst volume as 2,391 ft3 in Table F.3. 2,975 ft3 catalyst volume confirmed by NEC with Refinery 5 and via review of SCR data provided by Refinery 5 to SCAQMD.
2. Design value reported as 155 ppmv @ 0% O2. Value presented in table is corrected to 3% O2.
3. Measured outlet NOx value of <2 ppmv corresponds to operation of unit with inlet NOx in the range indicated. Removal efficiency based on range of actual operation.
4. Staff reports space velocity value of 2,974/hr in table F.3.
5. Confidential data provided by SCAQMD staff is insufficient to calculate the catalyst volume for this unit without making the following assumption on the depth of a catalyst module which we assume to be 45". Staff used ½ of this value in Table F.3 corresponding to catalyst bed depth (catalyst element height) of 22.5". Recommend staff confirm catalyst volume with Refinery 6.
6. Confidential data on unit design and performance, provided by SCAQMD staff, used to calculate inlet volumetric flow and space velocity. Values differ from staff's entries in Table F.3.

Response 2-3

Staff has looked over the values presented in the abovementioned revised comparison. It is difficult to confirm several of the values presented in this table and the notes. It is also important to note that the PDSR did not include the NEC model (proposed to achieve a 2ppmv emissions limit) in F.3. Staff referred to the 3-catalyst layer NEC approach that was presented in the Non-Confidential Final Report. The NEC data were encumbered in the Confidential Reports as a model for scaling FCCU SCR specifications and costs to the appropriate FCCU application. Furthermore, it should be noted that staff did not estimate the catalyst volumes or space velocities for Refinery 1, 6 or 5 as NEC stated in the footnotes of Table 1 above. The numbers included in the PDSR were either reported by the refineries through the Survey or documented in the permit applications. Staff confirmed with Refinery 6 on the FCCU SCR catalyst volume and Refinery 6 reported the catalyst volume was not 6,200 cubic feet as estimated by NEC in Table 1 above.

In addition, it is important to note that staff's analysis in the PDSR relied on the manufacturers' cost data provided to staff which did not project based on any specific superficial gas velocity or space velocity. The manufacturers provided costs based on a profile of the SCR currently used at Refinery 1 that rely on 2 layers of catalysts to meet 2 ppmv BARCT level. The bottom line is that NEC's added cost based on a design including 3 layers of catalysts would not affect the overall conclusion on the cost-effectiveness of the FCCU SCRs and would not impact the total proposed reduction in RTC holdings.

Comment 2-4 NEC's "Typical" FCCU SCR Design

In their review, staff is suggesting that NEC's typical SCR is overdesigned and as a result overpriced. Staff's comparisons suggest an overdesign factor of as much as 284%. We do not agree with this assessment. As can be seen in Table 1 (shown in Comment 2-3) , NEC's typical SCR should be able to achieve 97% NOx reduction by virtue of the addition of catalyst at higher gas velocities than the SCR operating at Refinery 1. The typical SCR design provides an approximate 21% margin in space velocity over the Refinery 1 SCR design primarily due to the addition of a third catalyst bed. The addition of a third bed has inherent performance advantages in that it provides for partial redistribution of unreacted NH_3 and NOx versus further cross sectional area additions. If it is determined that the incremental cost of specially fabricated catalyst modules (shorter depth) is low, some further optimization may be possible to reduce SCR cost. It is worth noting that the ~21% catalyst margin will have a 12% overall TIC and PWV cost impact.

Response 2-4

In reexamining our evaluation, staff agrees that your typical SCR is not overpriced. Staff also understands the reasoning for your selection of a third catalyst bed, and as previously discussed, the PDSR erred in catalyst volume calculation. However, even with a 3rd catalyst bed the change in overall cost-effectiveness would not impact the total programmatic shave. Staff will continue to utilize our approach in deriving the costs based on the manufacturers' information and Refinery 1's profile of 2 layers of catalysts to meet 2 ppmv BARCT level.

Comment 2-5 Mark-up factor 1.35

The following paragraphs provide background for NEC's use of a 35% conditioning factor for vendor equipment quotes at early stages of projects. These concepts were discussed with SCAQMD staff during reviews of our report and in subsequent follow-up phone conversations and e-mails. Due to the extensive discussion around this topic we are mystified by staff's characterization of this "bid conditioning factor" as, and here I paraphrase, 'an undefined and therefore invalid cost increase'.

Obtaining budgetary quotations from vendors for their equipment is part of the process of developing cost estimates for any project. At the early stages of projects, or when general information is sought, vendors are not provided comprehensive design basis information and therefore do not have a complete picture of the operating envelope for their proposed equipment. In these instances, some vendors will use costs from recent projects and "factor" them to the provided process conditions, other vendors may develop estimates based on equipment designed specifically to meet the provided process conditions. In either eventuality, the vendor is providing a quality estimate with reasonable accuracy (about +/- 10%) for the specified process conditions, without providing a performance guarantee and without review of the specific codes and standards applicable to refinery installations.

As project definition improves the process basis becomes fixed, equipment sizes become more reliable, performance guarantees are finalized, and vendor quote accuracy improves. Industry experience shows that at the early stages of a project, basis uncertainty alone, necessitates the addition of a 15 – 25% conditioning factor to a vendor's budget quote, in addition to other bid conditioning factors, to account for the difference seen between early equipment bids and final, full definition, performance guaranteed, equipment bids based on a definitive project basis.

Refineries are built to a more rigorous set of standards than typical air pollution control equipment which makes projects in the refining sector slightly more expensive than typical industrial projects. Standards which will have an impact on either the SCR design, the structural support design, location of equipment, internal and external maintenance access, etc., are likely to increase Direct SCR M&L costs. At this stage of project definition a factor of 10% is added to a vendor's equipment bid to account for the cost of meeting local plant standards.

The 1.35 "mark-up" or bid conditioning factor used in NEC's cost work-up for all SCR projects (FCCU, Heaters/Boilers, etc.) is not an arbitrary factor used to inflate costs, as implied in Appendix F, but is actually the low end of a time tested and proven means to determine the actual cost of a piece of equipment after full project definition is complete, including application of local industry standards to the design of the equipment, performance guarantees are offered and firm pricing for equipment components is provided by the vendor.

Response 2-5

Staff appreciates the in-depth background information of the bid conditioning factor, and regret the inclusion of language characterizing the use of the factor as "invalid". The PDSR approach relies on the EPA model defined in Appendix A with a 50% contingency factor added to the cost estimate. However, staff recognizes NEC's expertise in evaluating costs to place equipment in operation, but we will continue to utilize our approach in deriving the costs and will present your derived results for comparison. Staff derived the SCR costs for Refinery 5, 6 and 7 based on

Refinery 1 actual costs, thus the bid conditioning is not applicable here. For Refinery 4 and 9, the SCR costs were based on the costs provided by several prominent manufacturers and since SCR is a mature technology, staff feels that a 50% contingency factor is sufficient. Even if the bid conditioning factor was used, staff's estimates would be $163 million for 5 SCRs at Refinery 5, 6, 7, 4 and 9 (Appendix F) compared to $211 million as estimated by NEC. The bottom line is that NEC's estimates of $211 million would not affect the overall conclusion on the cost-effectiveness of the FCCU SCRs and would not impact the total the total programmatic shave.

Comment 2-6 75% increase in labor to the costs of the SCR

Another cost factor discussed with SCAQMD staff, and apparently dismissed as a simple adder to make costs appear high, is the cost of actually installing the equipment supplied by the SCR vendor in the plant. The vendor does not do construction and does not quote the cost of field assembly in their quote which only covers fabrication and supply of the equipment, in this case the SCR catalyst, support frames, ammonia injection grid and the carbon steel box.

The labor cost factor used in NEC's development of project costs is applied to the SCR vendor's factored estimate to account for the labor required to install the manufacturer's equipment at the site, transportation, taxes, tie-ins, insulation, access, structural steel, etc. Installation labor for equipment can range from a low of about 30% of the equipment cost to as much as 200% of direct equipment cost depending on the complexity of the equipment, the material it is made of and other equipment specific factors. In general, low cost equipment manufactured of low cost materials have higher installation percentages than highly complex equipment made of high cost materials. As a reference point, "Applied Cost Engineering", Clark F. D. and Lorenzoni A. B.; Marcel Decker Inc., 1978, uses a factor of 2.2 times direct material costs to estimate the direct M&L cost of a fired heater installation, a factor of 3.0 times direct material costs to estimate the direct M&L cost of a pump installation and a factor of 2.9 to estimate the direct M&L cost of a distillation tower. Due to the simplicity of the SCR equipment and its use of low cost materials we have used an installation labor cost factor of 0.75 (75%) to account for physical installation of the SCR, structural steel, fit-up of ducting, connection of piping, foundations, excavation, instrumentation, insulation, equipment storage, etc. This factor does not account for any costs associated with: demolition of existing equipment, modification of existing equipment, labor inefficiencies attributed to working in an operating plant, relocation and/or modification to underground utilities, piping, piping supports, ammonia storage facilities, control system additions, instrumentation wiring, conduit, power wiring, area paving, area lighting, area utilities, safety facilities, soot blowers, etc.. The cost of these items is rolled up into the overall TIC factor applied to escalate SCR M&L costs to a total project cost.

Response 2-6

As with the bid conditioning factor, staff concurs that the NEC approach which adds a 75% labor cost factor is a valid alternate assessment of the projected project costs. As previously mentioned we will present the information that you used in your assessment but we will continue to utilize our approach in deriving the costs. The PDSR approach relies on the EPA model with a 50% contingency factor added to the cost estimate. The EPA model did not have the 75% labor cost factor. Since the SCR technology is commercially available for more than two decades, staff did not feel that a 75% increase in labor is a necessity. However, as shown in Table F.5, Appendix F, even if the 75% labor cost factor was included, staff's estimates would be $163 million for 5 SCRs at Refinery 5, 6, 7, 4 and 9 compared to $211 million estimated by NEC. The bottom line is that NEC's estimates of $211 million do not affect the overall conclusion on the cost-effectiveness of the FCCUs and do not impact the total the total programmatic shave.

Comment 2-7

SCAQMD staff disputes NEC's use of a TIC factor of 4.5 to convert direct M&L costs for the SCR into TIC for the SCR PROJECT. This factor is a reasonable estimate for project items not specifically identified in the direct M&L costs (indirect costs, engineering and owner's costs, labor productivity, ancillary equipment and systems, revamp items, duct work, area paving, lighting, utilities, safety systems, control system connections and programming, instrumentation, soot blowers, etc.) As a point of reference, the TIC factor used by NEC, in this analysis, is 90% of the average TIC factor of 4.9 used to estimate SOx control costs in NEC's SOx RECLAIM report.

Response 2-7

Staff appreciates NEC's position on the TIC factor and agree with the reasonableness behind its selection. After the NEC Non-Confidential Report was posted for review, staff met with refinery personnel and their consultants who provided examples of SCR equipment purchases and installations at out-of-state refineries. Their data supported a 4.0-4.5 factor for PWV evaluation. Appendix A of the PDSR uses the 4.5 factor as an upper bound of cost estimation for the FCCU SCR PWV and cost analysis (i.e. $163 million for SCRs with 2 layers of catalysts). Staff reevaluated the EPA methodology in conjunction with a 50% contingency factor (i.e. $152 million for SCRs with 2 layers of catalysts). Regardless, use of both methodologies provides a range of expected costs.

Comment 2-8

SCAQMD staff is correct in pointing out that NEC used incorrect design capacities in developing the FCCU SCR costs shown in section 1.2 of NEC's non-confidential report (14-045-4, November 26, 2014). NEC back calculated expected FCCU rates from flue gas flow rate data provided by AQMD staff to obtain estimated FCCU sizes. The following table presents a revision to the report table based on corrected FCCU sizes as indicated by district staff. Also included in the table is an update to the cost of a Grass Roots SCR for Refinery 6 based on a comparison of flue gas rates to the SCR versus the typical (base case) SCR. Revised NEC estimates provided in Table 2 do not include any reduction to NEC's original cost estimate model.

Response 2-8

Staff thanks NEC for back calculating the expected FCCU rates from the correct design capacities. However, staff cannot verify some of the assumption in footnote 1 that NEC used for Refinery 6 and thus we continue to present the $211 million that NEC estimated. The bottom line is that NEC's estimates of $211 million do not affect the overall conclusion on the cost-effectiveness of the FCCUs and do not impact the total the total programmatic shave.

Comment 2-9

Staff provided a review of NEC's cost estimates based on a comparison to the cost provided for Refinery 1's SCR to demonstrate that NEC's estimating method is overly conservative. In this comparison staff claims that NEC's cost tool over predicts the cost of this installation by $11M (27%). The difficulty in comparing a specific project to a generalized curve is that the project has a specific scope which in most cases is different than the assumed scope of the "typical" project. This is the case for the SCR installation at Refinery 1 which, according to Refinery 1 personnel, did not include the cost for waste heat boiler modifications. Subtracting this component from the TIC for a typical FCCU SCR installation and recalculating PWV yields a cost of $45.45M which is 10.8% higher than staff's cost work-up on this project of $41M, not the 26% difference indicated in Appendix F. Staff had the WHB cost information NEC used in our estimates, we do not understand why they did not make the PWV comparison on the same basis.

Response 2-9

The PDSR estimation of Refinery 1's PWV was based on data provided by refinery staff. Staff took the data reported by Refinery 1 as the total project cost for the SCR system including all peripheral equipment.

Comment 2-10

Staff also provided a review of NEC's cost estimates based on staff's assessment of differences between the data provided by an SCR vendor to staff and NEC for an installation at Refinery 9. In staff's evaluation of the data provided by the vendor they incorrectly calculate the total catalyst volume to be 3,100 ft^3 vs the actual vendor proposal which provided only 2,400 ft^3. Staff also incorrectly calculates NEC's estimated catalyst volume at 12,697 ft^3 vs an actual value of 4,600

ft^3 (1.92 x vendor proposal, see previous discussion on catalyst volumes and specification of a third bed).

Response 2-10

With regard to your second comment first, staff agrees that the catalyst volume was incorrectly presented in the PDSR. The 12,697 ft3 actually represents the total SCR volume. As presented in the PDSR, the manufacturer's recommendation for the Refinery 9 catalyst volume was 3,300 ft3. A review of the data provided by the SCR manufactures will be conducted to conform to proposed specifications and correct any misrepresentations in the PDSR.

Comment 2-11

NEC provides a few comments on SCAQMD staff's determination of PWVs for FCCU SCRs.

1. In using the costs provided for Refinery 1's SCR staff is assuming that all district SCRs can be installed without any impact on upstream equipment and that installation of the SCR can be executed in an open, non congested area. Refinery 1's SCR was installed prior to the installation of a large ESP, which occurred around 2006. If the SCR was to be installed today, or at any time after installation of the large ESP, costs would be higher due to productivity debits associated with working in a congested area and quite possibly even higher due to the need to move or modify some equipment to make the installation possible. In the most extreme case the SCR and ducting may have to be field erected from small fabricated assemblies due to access constraints.

2. Staff used a 0.7 power factor to scale the costs for Refinery 1's SCR project to different sizes. Costs for FCCU regenerator flue gas systems scale more accurately when a figure of around 0.6 is used. The effect of using a larger scale factor is a greater reduction in project costs for all projects with the differences getting proportionately greater the further one gets from the base case unit size. In essence using the 0.7 factor instead of 0.6, in this particular evaluation, will decrease costs for all units and will disproportionately decrease the cost of smaller units.

3. In using vendor budget quotes for SCRs, staff needs to add erection labor to the vendor quote. There is no indication that this is done in staff's analysis.

4. Staff does not condition the vendor's quotes to account for operational conditions, including unit upsets, and other project unknowns which will have direct bearing on SCR design details, performance and costs. An allowance must also be made for the accuracy inherent in vendor's budget quotations, which does not appear anywhere.

5. The PWVs provided for Refinery 7 and Refinery 9 are $27M and $19M respectively. There is an apparent inconsistency in these numbers as the stated capacity for each of these units is 55 kBPD. Units of the same capacity should have PWVs close to one another not differing by 42%. Staff should check these numbers and ensure that the SCR project scope differences between these two units can explain the large difference in cost.

Response 2-11

Again, staff appreciates and respect NEC's opinion with regards to our technical assessment of the FCCU costs. Staff notes areas of agreement and issues to be resolved.

1. Refinery 1 provided staff with comprehensive cost data for its FCCU SCR. As such, we used this model to estimate PWV and associated costs for other FCCUs where applicable. Your comments are correct in asserting the uniqueness of Refinery 1's situation, in particular the relative date of installation of an ESP to the FCCU. We realize that there are uncertainties in the cost estimate due to such considerations and have added a 50% contingency to our estimated costs. .

2. The PDSR based its scaling using a 0.7 factor established in practice and in the literature. The costs of $211 million estimated with the use of a 0.6 factor do not impact to the cost effectiveness calculation.

3. Staff concurs that the erection labor is a part of the installation costs included in the 4.5 factor

4. As previously stated, the PDSR cost estimates for the FCCUs included a 50% contingency factor to account for vendor cost estimation variability.

5. The PWVs for Refinery 7 and Refinery 9 were estimated using two different approaches. Refinery 7's PWV was estimated based on Refinery 1 actual cost data while Refinery 9's PWV was estimated based on the cost data submitted by the manufacturers. Originally, in 2013-2014 time frame, the manufacturers did not provide cost data for Refinery 7, 5 or 6 since these FCCUs already have SCRs or wet gas scrubbers. In Table F.5 of the PDSR, staff provided 2 different approaches to estimate the costs for Refinery 7 and Refinery 9. Using the manufacturer's cost data with 2 layers of catalysts and no markups, the PWVs for Refinery 7 and 9 would be $20 million. Using the manufacturer's cost data with 2 layers of catalysts and two levels of markups as recommended by NEC, the PWVs for Refinery 7 and 9 would be $31 million.

Comment Letter #3 – NORTON Engineering – September 4, 2015

General Comments

In its opening paragraph NEC is quoted “We stated, quite clearly, in the final report and in subsequent discussions with staff, that we agree that 2 ppmvd (3% O_2) NOx emissions is a justifiable emission level for SCR applications to FCCUs, Fired Heaters, Boilers, Gas Turbines and TGU/SRUs, with caveats. While a few existing units can meet this guideline under current operating conditions, many more, similarly designed units have not demonstrated similar low emissions capabilities. With the exception of Gas Turbine installations (which have an equivalent emission level of 6 ppmv @ 3% O_2) most low emission SCRs in service today, being built today and even those being designed today carry manufacturer’s guarantees to meet a NOx limit of 5 vppm @ 3% O_2. In spite of the limited number of units (other than gas turbines) operating at or below 2 vppm NOx, we believe that it is possible to achieve these levels, but to guarantee long term reliable performance (refineries typically operate 24/7 for periods of 4 to 6 years) it is prudent and quite possibly necessary to design future SCRs to increase residence time, improve NH_3 distribution, improve overall flue gas flow distribution, add catalyst, etc. SCAQMD staff agrees with this concept but we have strong disagreement as to how much change from current SCR designs will be required to achieve the sought after NOx reductions not only on day one but at the end of year one and year five and beyond.”

NEC also commented on the general approach to creating cost curves to determine an effective cost curve to represent the PWV vs the maximum boiler/heater firing rate. Their analysis highlighted the paucity of SCR data and questioned the linear approach taken by staff. They commented that their power law curve better captured the relationship (within error bounds) when applied to specific Basin refinery SCR cases. They expressed that their cost curve better represented smaller heaters (<100mmbtu/hr heat release).

Response to General Comments

Staff recognized the issue and has directly quoted the NEC disclaimer from in the Non-Confidential Report in Appendix B of the DSR to help define the primary difference in the control equipment specifications proposed by staff and NEC.

With regard to the cost curve development and application, staff’s analysis expanded beyond a solely SCR application to include control equipment including Great Southern Flameless Heaters, ClearSign Duplex technology for burners, as well as Electrodynamic Combustion Control technology. The staff analysis assessed the five sets of data to develop a set of representative PWVs to firing rates. Staff acknowledged in the DSR that cost curves developed by staff and NEC for higher firing rates converged and that the main difference was at firing rates less than 200 mmbtu. The differences between the cost curves generated by the varying control equipment design assumptions lead to the uncertainty reflected in the number of boilers and heaters deemed cost effective. The uncertainty as defined by the difference in emissions reduced 0.33 tpd for the category has been accounted for in the 0.85 tpd adjustment to the shave.

Comment 3-1 Scope of NEC's Review

NEC indicated that staff agreed with NEC that any dilution of NEC's effort to evaluate other alternative technologies than SCRs would not be desirable.

Response 3-1

Staff agrees that during an in-person conversation with Mr. Norton, the general understanding was for NEC to focus on SCRs as the primary control methodology. Regardless, staff sent to NEC information related to all control technologies discussed in Appendix A to Appendix E including technical studies, technical analyses, data that the refineries submitted as a result of the Survey, data that staff received from the manufacturers, facility drawings, facility permits, and manufacturers' contacts for NEC to review. In an email, staff also introduced NEC to all of the manufacturers that staff contacted.

Comment 3-2 Using FCC SCR Costs Increased Heater & Boiler SCR Cost Estimates

NEC explained the reasons that NEC elected to use FCCU SCR as the basis for its analysis for heater and boiler SCR. They cited uncertainty in vendor's response to their inquiries for additional data. They favorably compared a Basin refinery heater that achieved 1.6 ppmv to their FCCU SCR design and increase the costs to reflect installation of duct fan, new CEMS and ammonia storage tank.

Response 3-2

Staff agreed with NEC that the catalysts for FCCUs are not the same as the catalysts for boilers and heaters. Several prominent manufacturers indicated that a high dust application such as FCCU require a catalyst flow passage (or pitch) of about 7 mm. The refinery boiler and heater is a low dust application, and the catalyst pitch for this application is about 3 mm. The SCR for a refinery boiler and heater is generally compact and contains 1 layer of catalysts. The FCCU SCR contains 2 to 4 layers of catalysts, 2 or more filled with catalysts and 1 possible spare. The FCCU SCR has a large box area designed to fit additional equipment such as soot blower. Staff contends that NEC recommendation of 3 layers of catalysts for a FCCU SCR and 4 layers of catalysts for a boiler and heater SCR designed at 10 feet per second is different than a design provided by several prominent SCR manufacturers.

The SCAQMD facility permit database contains information on the catalyst volumes of the SCRs currently in operation in the District. The table below shows the catalyst volumes for several SCRs at the refineries, the rating for the boilers/heaters in mmbtu/hr, and the NOx emissions in ppmv that the refineries reported through the Survey. On average, the catalyst volume for the boiler and heater SCRs achieving 2 - 7 ppmv NOx is about 0.96 cubic feet of catalysts per mmbtu/hr based on the information in the facility permit database. The manufacturers indicated that the amount of catalysts needed to achieve 2 ppmv NOx is about 293 cubic feet for a 300 mmbtu/hr heater, and 92 cubic feet for 100 mmbtu/hr heater, or on average 0.96 cubic feet per mmbtu/hr. Staff estimated about 1.2 cubic feet per mmbtu/hr.

Table Z. 1 – Comparison of Information for Boiler and Heater SCR

Process Data	NOx Emissions from Survey (ppmv)	Heaters/Boilers' Rating from Facility Permit Database (mmbtu/hr)	Catalyst Volume from Facility Permit Database (cubic feet)
SCR for 4 catalytic reformer heaters	1.64	589	537
SCR for a hydrotreating heater	2.26	78	92
SCR for 3 coker heaters	2.71	528	623
SCR for a crude distillation heater	2.7	83	62
SCR for a hydrogen plant heater	2.7	653	691
SCR for 3 hydrotreating heaters	2.67	63	92
SCR for a crude heater	3.31	85	96
SCR for a crude heater	5	300	120
SCR for a boiler	5.39	245	225
SCR for 3 crude distillation heaters	5.69	849	810
Average catalyst volume using information from facility permit database (cubic feet per mmbtu/hr)			0.96
Catalyst volume provided by manufacturers for 2 ppmv SCRs (cubic feet per mmbtu/hr))			0.96
Catalyst volume estimated by Staff (cubic feet per mmbtu/hr)			1.2
Catalyst volume provided by NEC (cubic feet per mmbtu/hr)			17

Comment 3-3 NEC TIC Factor of 4.5 vs. Staff TIC Factor of 3.8

NEC explained the reasons that NEC elected to use a factor of 4.5 and the need to adjust vendor costs to include ancillary equipment such as ducting, fans, CEMS.

Response 3-3

Staff agreed with NEC and the refineries to use a factor of 4.5 and adjusted vendor costs to include ancillary equipment such as ducting, fans, CEMS. Staff revised the estimates prior to the release of the PDSR. The revised estimates resulted in slightly lower incremental emission reductions at a nominal increase in cost.

Comment 3-4 Basis for SCR Catalyst Increase and Velocity Reductions vs Vendor Budget Quotes

NEC indicated that staff analysis was based on only one SCR achieving 1.6 ppmv. This SCR has 1 layer of catalysts, however the heaters were fired at 65% capacity. NEC indicated that the vendor information provided by AQMD staff indicated that doubling a vendor catalyst volumes would be needed to ensure reliable operation in excess of five years, thus the minimum number of layers of catalysts needed would be 1 layer x 2 / 0.65 = 3 layers. NEC recommended 4 layers to ensure long term compliance while burning variable composition of refinery fuel gas. NEC also recommended 10 feet per second instead of 12 feet per second velocity as recommended by the manufacturers.

Response 3-4

Several prominent manufacturers indicated that one layer of catalysts is sufficient for a heater and boiler (or a gas turbine, or a SRU/TGTU incinerator) firing with refinery fuel gas. The SCR is typically designed at full rated capacity of the heater and boiler to sustain an operation between 3-year to 5-year turnaround period. The manufacturers indicated that even though the refinery fuel gas may contain some components (e.g. sulfur) that may poison the SCR catalysts, they have not yet seen a significant impact on catalyst poisoning in refinery fuel gas applications. The manufacturers indicated that a well-designed and maintained SCR system with good ammonia distribution system can meet 2 ppmv NOx.

Comment 3-5 Cost of New CEMS vs Upgrade and Ammonia Tank

NEC indicated that they did not have any data on the status/condition of existing CEMS. NEC proposed the cost of a new CEMS at an approximate cost of $1 million. NEC indicated that they used used a common 11,000 gallons ammonia tank for all sizes of heaters and boilers in their proposals.

Response 3-5

The cost of $1 million for CEMS is not consistent with the information submitted in CEMS applications. Staff understand the reason for a common 11,000 gallons ammonia tank and included the costs for ammonia tanks as recommended by NEC in the revised estimates prior to the release of the PDSR. This adjustment results in nominal change in costs.

Comment 3-6 High Catalyst Replacement Costs Skewed NEC PWVs High

NEC indicated that NEC agreed with staff that replacement costs of the 4-layer SCR catalyst system would skew NEC PWV higher and NEC corrected their estimates.

Response 3-6

Staff concurs.

Comment 3-7 NEC's estimates are higher than staff's "conservative" PWVs

The SCR listed in PDSR Table G.8 is shared between four heaters. The combined total rated capacity of the four heaters is 589 mmbtu/hr. NEC indicated that staff should have used $43.2 million as an estimate for a shared SCR of a 589 mmbtu/hr heater compared with $38.5 million to the total costs of the four individual SCRs that staff estimated. NEC estimated that 4 individual SCR units installed to meet the 589 mmbtu rating would require $99 M.

Response 3-7

Staff agrees that the common stack-shared SCR application is more appropriate and less costly that individual units being installed. NEC also noted that the difference in costs estimated by staff and their engineers was less than 12 percent.

Comment Letter #4 - RECLAIM Industry Coalition, August 21, 2015

Comment 4-1 Shave amount and timing

A shave of 4 tons per day in 2016 does not allow any time for facilities to develop and implement emission reduction measures. The Coalition believes that the shave amount for the period 2016-2017 should be no more than 2 tons per day, and that there is no reason that all two tons have to be shaved in 2016.

Response 4-1

With respect to the implementation time, because the implementation date for 2 tpd reductions in Control Measure CMB-01 Phase 1 was past due in 2014 and there are 5-8 tpd surplus RTCs in the market, staff believes that at a minimum 2 tpd reduction or up to 4 tpd reduction should be removed from the market no later than 2016-2017. Staff disagrees that this proposal does not allow adequate time for implementation because there are sufficient unused RTCs in the market to allow a 4 ton shave in 2016-2017 without requiring controls to be installed in those years. The removal of unused RTCs would raise the RTC prices and stimulate the implementation of control equipment. It is urgent to implement the control equipment and reduce actual emissions as expeditiously as possible to meet the NAAQS for PM2.5 and ozone.

Comment 4-2 Shave amount and timing

There is no commitment in the AQMP to make a 4-ton per day shave in 2016. The AQMP contemplated a 2-3 ton per day reduction in Phase I and another 1-2 tons per day in Phase II. With respect to the total amount of the shave, the Coalition continues to believe that shaving a total of 14 tons per day of RTCs from the RECLAIM market in order to achieve the 8.79 tons per day reductions the District seeks to obtain as a BARCT adjustment is neither necessary nor justified

Response 4-2
Please see Response 1-2.

Comment 4-3 Cost effectiveness

The Coalition continues to believe that a 25 year useful life assumption (used consistently for all equipment in this proposed rulemaking) is not appropriate for all equipment.

Response 4-3
Please see Response 1-4.

Comment 4-4 Cost effectiveness

District staff minimizes control costs by using a cost-effectiveness calculation that is not used by the California Air Resources Board and most other major California air districts (i.e. LCF Method). Additionally, the use of a $50,000 per ton figure (i.e. based on DCF method) as the cost threshold is more than twice the $22,500 per ton threshold (i.e. based on LCF method) applied to command-and-control regulated sources.

Response 4-4
Please see Response 1-9.

Comment 4-5 Cost effectiveness

We also note that Norton Engineering (the third party independent contractor retained by the District to review and assess the District staff's cost effectiveness determinations) has raised questions regarding the District staff's cost effectiveness determinations and its dismissal of Norton Engineering's analyses when those analyses showed higher costs than the District staff's evaluation showed.

Response 4-5
Please see Responses 1-6.

Comment 4-6 Need for the "gap"

Our analysis has shown that even if the District staff concluded that NO BARCT improvements had been made between 2005 and today, the staff's methodology would result in 6 tons per day of NOx RTCs being removed from the program. RTCs being removed under the District's methodology would include those needed for 1) NSR Holding Requirements, 2) Electric Grid Reliability and Implementation of AQMP Attainment Strategies (i.e., large scale electrification to replace current combustion processes), 3) Post-2023 Growth, 4) Investor Holdings, 5) Shutdowns and 6) ERC Conversions. The Regional NSR Holding Account is to be used for both NSR Holdings and to cover actual emissions in certain cases which raises the question of whether it is large enough. The shave of 14 tpd is too large and runs the risk of repeating the program "meltdown" of 2000-2001 during the power crisis when insufficient RTCs were available.

Response 4-6

Staff agrees with the commenter that using the staff's methodology (Figure EX-1), if there were no new 2015 BARCT, the RTC shave would be:

Allocations – (2011 emissions at 2005 BARCT x 1.1 for 10% compliance margin) = 26.5 – (1.1 x 18.3) = 6.4 tpd

This shows that the 2005 shave was not large enough to remove the unused RTCs (or the "gap") to the level that can stimulate the installation of actual control devices. Thus, in the past 10 years since 2005, there was only 4 SCRs installed at the refineries even though staff had estimated that it was feasible and cost effective for the refineries to install 51 SCRs by 2011.

Staff methodology in estimating the remaining emissions in 2023 does include the impact of growth to 2023 and the possibility of returning operation for shutdown facilities and new electric generating facilities. Staff may need to revisit the NOx RECLAIM post 2023 to incorporate advancement in control technology, but it is not appropriate to include post-2023 growth in the 2023 target as this will result in an artificially high target. Staff also creates a separate Regional NSR Holding Account to address the NSR holding requirements for new power producing facilities and is in the process of discussing with EPA to seek its approval. Moreover, the NSR Holding requirement and the use for power emergencies are not additive. Since the facility NSR Holding requirement is its maximum potential to emit, actual emissions will always be smaller and will be covered by the same RTCs used for the NSR Holding requirement. Investor holdings and ERC conversions are subject to shave consistent with the previous 2005 and 2010 RECLAIM amendments. Staff has accounted for electric reliability by allowing "nontradable/nonusable" RTCs to become usable by power producers if a grid reliability emergency is declared. Staff has accounted for increase electrification through the growth factor which assumes increased use of renewables. Note that ERCs of non-RECLAIM facilities do not hold their values to eternity, they are often recalled and reduced per Regulation XIII. Rule 2002 (f)(1) contains a safety valve to provide a stability for the RECLAIM market and ensure that when RTCs are not sufficiently available (i.e. the 12-month rolling average RTC price exceeds $15,000 per ton), staff can convert the non-tradable/non-usable RTCs to tradable/usable RTCs upon the concurrence of the Governing Board.

Comment 4-7 Energy efficiency projects

The Coalition strongly opposes any effort to further reduce RTC allocations due to "energy efficiency projects" that have or would reduce NOx emissions. Any reduction in NOx emissions not strictly required by BARCT should be encouraged and the benefits of making those reductions retained by the facility operator making them.

Response 4-7

Staff did not consider further reduce RTC allocations due to energy efficiency projects at this time. However, it should be noted that the energy efficiency projects resulted in 0.7 tpd concurrent reductions of NOx completed in 2011, and the RTC allocations adjusted in 2005 have not yet been reduced to account for these reductions.

Comment Letter #5 – Latham & Watkins, August 20, 2015

Comment 5-1 March 20, 2015 freeze date for shave estimation

The first time Harbor Cogeneration Company (HCC) was made aware of the freeze date of March 20, 2015 for shave estimation was just prior to the public workshop on July 22, 2015. However, staff proposal to establish a retroactive baseline date without prior advance notice constitutes an unprecedented ex post facto action that unfairly disadvantages entities that have made good faith trades after March 20. Two examples were provided and the commenter suggested the District propose the date of rule amendment as the freeze date for shave estimation.

Response 5-1

Staff has revised the proposal and notified the stakeholders regarding the proposed new freeze date of September 22, 2015. Staff cannot practically make the freeze date for shave estimation the date of rule amendment because the rule language and calculation of shave must be completed for public review and comment prior to the Governing Board hearing for rule adoption. Staff disagrees that setting the freeze date prior to rule adoption is an "ex post facto" regulation. The prohibition on "ex post facto" laws or regulations applies to making conduct criminal that was not criminal when it occurred, or increasing the criminal penalty [in re Lomax, 66 Cal. App 4^{th} 639 (1998)]. In contrast, ordinary civil law may be made retroactive, but it must be expressly so stated in the language, or state statute, or clear form extrinsic evidence [Myers v Philip Morris Companies, Inc., 28 Cal 4^{th} 828 (2002)].

Comment Letter #6 – Yorke Engineering, LLC., August 21, 2015

Comment 6-1 New Emission Factors for Rule 219 Exempt Equipment

We support the District's August 19th proposal for new provisions in Rule 2012 Chapter 4 to allow equipment certified by either U.S. EPA, CARB, or SCAQMD to use an emission factor other than the default factor of 130 lb/mmscf to report NOx emissions.

Response 6-1

An August 19th presentation by staff acknowledged the issue and mentioned a possible path forward relying on source tests rather than the default factor. Based on feedback form stakeholders, the concept did not seem to achieve the goals of the request, and thus, staff is not proposing an alternative to the default factors at this time.

Comment 6-2 Source Test for Rule 219 Equipment

The District's August 19th proposal for certified Rule 219 exempt equipment indicates source tests may be required to verify lower emissions. We request that no source test shall be required for certified equipment.

Response 6-2

Source testing is the preferred method of verifying the certified emissions for these units. The RECLAIM program offers the flexibility of a market program, but also has stricter standards for emission reporting than many command and control regulations. Based on feedback from stakeholders, the concept did not seem to achieve the goals of the request, and thus, staff is not proposing an alternative to the default factors at this time.

Comment 6-3 RTU Reporting

The current requirements are specified in 2012 Appendix A, Chapter 7 – Remote Terminal Unit (RTU) Electronic Reporting. This section of the rule requires facilities to use dial-up modem technology to transmit a text string that must be very specifically formatted. We have wasted hours of time working with this antiquated system which is still required by the regulation. We urgently request that the District update their electronic reporting system to allow more modern and easy to use technology.

Response 6-3

We agree that the electronic reporting system needs to be updated. This upgrade, however, would be very resource intensive for SCAQMD staff and the affected operators and is outside the scope of this rule making. The RTU electronic reporting system will be upgraded and the corresponding rulemaking will occur at that time.

Letter # 7 - Charles F. Timms, Jr. August 21, 2015

Comment 7-1 Electric Generating Facilities Need Quicker Access to Non-tradable/Non-usable RTCs

Based on the experience of power plants during the energy crisis of 2000-2001, this cumbersome, two-step process for releasing these RTCs to cover annual emissions appears to be too slow to avoid skyrocketing spot prices or an outright shortage of RTCs for power plants to either cover annual emissions or demonstrate resource adequacy. We understand that the Los Angeles Department of Water and Power will be presenting a more detailed description of how the two-step process for releasing RTCs during the energy crisis of 2000-2001 did not avoid high prices and shortages of RTCs at that time.

The Cities therefore suggest that a provision be added allowing power plants to request that some or all of this pool of non-tradable, non-usable RTCs be converted to usable but non-tradable RTCs, in exchange for a fee of $7.50 per pound. Once converted, the RTCs could be used to cover annual emissions or meet resource adequacy needs for the year in which the request is made, but they could not be traded. In addition, the power plant also would not be allowed to trade any of its own RTC allocation for the year in which the request to convert is made.

The fee serves two purposes. First, it gives power plants the incentive to rely on the RTC market if the spot price remains below $7.50 per pound. As long as the spot price of RTCs remains below that level, power plants will not have an economic incentive to make a request to convert. Instead, they will rely on the RTC market to acquire additional needed RTCs. But if the spot price rises above $7.50 per pound, then they will have an incentive to make a request, if they deem it prudent to do so. Of course, power plants would be free to wait for the slower two-step process to unfold regarding the 12-month rolling average price, and obtain additional unrestricted RTCs without a fee, if they deem that to be the more prudent course.

The fee also serves the purpose of providing the District with funds to achieve additional NOx reductions from other sources, including mobile sources, for which cost-effective reductions cannot otherwise be obtained.

Response 7-1

SCAQMD staff has taken your comments into consideration and has proposed a mechanism for accessing non-tradable/non-usable credits and also credits in the Regional NSR Holding Account with associated triggers. For the first year of the shave, the entire non-tradable/non-usable portion of a facility may be accessed if the rolling 12-month RTC price exceeds $15,000/ton. Those credits would become usable and tradable. The non-tradable/non-usable credits would also be accessed if the Governor of California declares a State of Emergency, but would be usable/non-tradable.

Staff is not proposing a fee for access to the Regional NSR Holding Account due to comments received at Working Group and other meetings from many other electric generating facilities that a fee should not be imposed for using these credits.

The commenter also expresses that the non-tradable/non-usable RTCs not be removed from the facility permits after the end of the shave as these credits will be greatly needed then. Staff has established the Regional NSR Holding Account such that the non-tradable credits for newer electrical generation facilities that would normally go to the SIP after one year for each year of the shave would now go in the Regional account every year of the shave beginning in 2017. So when the shave is complete, the shaved portion would be available to meet NSR purposes for these facilities and also provide relief in the event of a power crisis. A regional hold account offers more flexibility than if each facility held the amount reduced for their facility. For example, if there is a power emergency, not every facility will need to run. One or more facilities may be non-operational, and it is conceivable that not all facilities will be called on to the same extent to operate during an emergency.

Comment 7-2

As mentioned earlier, the staff proposal contains an "Adjustment Account" enabling post-1993 power plants to meet the NSR holding requirement on a programmatic basis. We understand that staff estimates that 1 to 1 ½ tons of RTCs will be needed for this account [see Draft Staff Report at p. 33]. We suggest that the RTCs in this account also be made available to affected facilities to cover their annual emissions, in exchange for a fee of $7.50 per pound. There does not appear to be any impediment to allowing the RTCs involved to serve both purposes.

As in the case of a request to convert non-tradable, non-usable RTCs to usable but non-tradable RTCs, the fee serves the dual purpose of giving power plants the incentive to rely on the RTC market if the spot price remains below $7.50 per pound, and also providing the District with funds to achieve additional NOx reductions from other sources for which cost-effective reductions cannot otherwise be obtained.

This use of the "Adjustment Account" could be viewed as an alternative to the suggested provision regarding the non-tradable, non-usable RTCs discussed above.

Attachment 2 to this letter contains an example of rule language that might be used to allow RTCs in the "Adjustment Account" to both meet the NSR holding requirement and be available to cover annual emissions.

Response 7-2

As stated in the previous response, access to the Regional NSR Holding Account would be for credits that could cover NSR holding requirements for newer electrical generating facilities, as well as covering annual emissions for all electrical generating facilities in the event of a power crisis.

Comment 7-3

Two suggestions on the provisions related to the RATA testing:

> First, the due date for performing the RATA should be 30 days, rather than 14 days, from the re-firing of the major source. The additional time is needed in some circumstances to perform tests on the source to ensure reliable and safe operation. [See PAR 2012, Appendix A, Attachment C, Section (B)(2)(c)]
>
> Second, the proposed requirement to disconnect and flange the fuel feed lines is unnecessary and costly. The proposed requirement is unnecessary because the fuel meters are required to be maintained, associated fuel records are required to be kept, and stack emissions are continuously monitored and recorded. So there are multiple sources of data to rely on to verify that the source is not operating. The proposed requirement is costly and time consuming because significant manpower and equipment would be needed to meet it. There also may be health and safety risks if asbestos-containing materials are encountered in the work. The Cities therefore suggest that this requirement be deleted. [See PAR 2012, Appendix A, Attachment C, Section (B)(2)(c)]

Response 7-3

Staff believes that the due date of 14 operating days from re-firing of a major source is sufficient for performing a RATA. The operating days do not have to be consecutive days so the total calendar days since the re-firing could be longer.

The proposed amendment for requiring the disconnection and flanging of fuel feed lines to demonstrate non-operation is necessary because this is the only reliable way to ensure that SCAQMD compliance staff can visibly confirm non-operation and no fuel flow. This prevents possible circumvention for other existing methods of demonstrating non-operation such as stack emission monitoring and recordkeeping.

Comment 7-4

a. Provisions Involving the Non-tradable, Non-usable Adjustment Factor

i. The staff proposal should be clarified to provide that the 12-month rolling average RTC price that may trigger release of the non-tradable, non-usable RTCs is the "weighted" average. [PAR 2002(f)(1)(E)]

ii. The staff proposal speaks of determining the 12-month rolling average RTC price for all trades in the "current compliance year." It is not clear how this language would apply to a 12-month rolling average price when the 12 months in question straddle two adjacent compliance years. [PAR 2002(f)(1)(E)]

iii. In PAR 2002(f)(1)(F), the correct cross-reference appears to be to PAR 2002(f)(1)(E), not PAR 2002(f)(1)(F).

Response 7-4

The comment discusses the provisions regarding the non-tradable, non-usable adjustment factors. The commenter states that 12-month rolling average should be a weighted average. Staff calculates the rolling 12-month average by totaling the dollar sum of all the sales and dividing by the total sum of all the pounds (or tons). This price is reported monthly to the stationary source committee. The commenter also questions how the 12-month rolling average is determined for all trades in the current compliance year when there are two cycles that overlap. Staff calculates the 12-month rolling average for all trades including cross-cycle transactions, but not including RTC transactions reported at no price or RTC swap transactions. The commenter also pointed out a rule reference error in PAR 2002 (f)(1)(F). Staff has corrected the reference.

Comment 7-5

b. Provisions Involving the "Adjustment Account"

i. The staff proposal includes a provision allowing access to "Adjustment Account" RTCs for the purpose of compliance with annual emissions during a State of Emergency as declared by the Governor. [see PAR 2002(f)(5)] This provision raises several questions:

(1) How is the account to be funded for this purpose, and with what quantity of RTCs? As we indicated earlier, we understand that staff estimates that 1 to 1 ½

tons will be needed to meet the NSR holding requirement. Will additional amounts be added to fund the account to allow compliance with annual emissions?

(2) Why is access to RTCs limited to a State of Emergency declared by the Governor, as opposed to a State of Emergency declared by a local government official, such as a Mayor?

(3) We understand that in response to questions raised at the Working Group meeting on August 19, District staff indicated that RTCs in this account can be used both to meet the NSR holding requirement and to cover annual emissions. If our understanding is correct, then the rule language needs to be clarified.

(4) It may not be appropriate for the Executive Officer to have unfettered discretion to determine the amount and distribution of RTCs. By making these determinations, he would in effect decide which power plants generate electricity during a State of Emergency. Such decisions may be beyond his authority and expertise. It is important, moreover, that every power plant have access to the RTCs it needs to meet its operating requirements.

Response 7-5

The comment discusses the provisions involving the Regional NSR Holding Account (previously called the Regional NSR Holding Account). The commenter asks how the account will be funded and whether additional funds will be needed to allow compliance with annual emissions. The Regional NSR Account will be funded up to the amount that is shaved from those electric generating facilities that have multi-year NSR holding requirements each year of the shave. As stated in Response 7-1, for the first year of the shave the entire non-tradable/non-usable portion of a facility may be accessed if the rolling 12-month RTC price exceeds $15,000/ton. Those credits would become usable and tradable. The non-tradable/non-usable credits would also be available for offsetting emissions if the Governor of California declares a State of Emergency related to power generation or grid stability, but would be usable/non-tradable. For NSR holding purposes, newer electrical generation facilities can access both their non-tradable/non-usable RTCs and the Regional NSR Holding Account RTCs.

The commenter also asks why the State of Emergency declaration can only be made by the Governor and not by a local government official. Staff believes that a major power crisis would warrant this type of declaration and not just an elevation in power demand. Staff understands that there are other factors to consider, such as the increase in the electrification in the transportation sector that may cause the demand to rise. Combined with the lesser amount of RTCs available as a result of the shave and higher resultant RTC prices, power-producing facilities may need some relief to gain access to more RTCs. Staff feels that the safety valves in the proposed amendment would address these concerns. Nonetheless, staff proposes to add resolution language to monitor the power-producing sector for trends in power consumption and associated NOx emissions as electricity demand potentially increases.

The commenter also states that the rule language needs to be clarified to detail that the Regional NSR Holding Account would accommodate NSR requirements and annual emissions in the event of a power crisis. Staff has made these clarifications in the rule language and staff report.

The commenter lastly states that it may not be appropriate for the Executive Officer to determine the amount and distribution of RTCs and thereby make the determination of which electric generating facilities would generate electricity during a State of Emergency. Each individual electric generating facility subject to the shave would also have access to its non-tradable/non-usable account if the 12-month rolling average RTC price threshold trigger is reached, or if a State of Emergency is declared. The credits in the Regional NSR Holding Account would also be made available to all electric generating facilities under a State of Emergency. If the State of Emergency is prolonged, the proposed amendments now provide for a report to the Governing Board after any power crisis trigger such that a plan for distribution of RTCs and possible program adjustments can be made before the supply of emergency RTCs is exhausted.

Comment Letter # 8 – SCEC Dated August 26, 2015

Comment 8-1

Responsiveness of Mitigating Actions. The Cities are concerned that rolling average RTC price may trail too far behind sudden RTC price increases and the requirement to obtain Governing Board authorization to convert the holdings to tradable and useable credits may not be suitably responsive to our needs as municipal utilities. In other words, the Cities' need for certainty and swift access to RTCs may be jeopardized and we will be forced to participate in a market with escalating costs and limited RTC availability until the point that the $15,000 threshold is reached. By the time the SCAQMD responses are implemented, it will be too late to undo the damage to the utilities and local communities.

Response 8-1

The comment states that if access to additional credits can be realized in a faster timeframe for unforeseen situations where emergency power generation may be necessary. The staff proposal has safety valves through which additional credits can be accessed, including the immediate access in the event of a power crisis. We understand that there may be some situations where the need to additional credits may arise more rapidly than, for example, a gradual upward trend in power generation. A facility would still have time to reconcile emissions at the end of a compliance quarter and compliance year, which include a reconciliation period.

Comment 8-2

Request for Flexibility in Accessing Non-tradeable / Non-useable Holdings. The Cities are supportive of the proposals to expand access to credits (at either no costs or $7.50 per pound which is equivalent to $15,000 per ton) and believe that they would be beneficial to the utilities and the RECLAIM program in general. By providing access to these credits in advance of a market upset, the District would provide municipal utilities the certainty needed to meet our mission at a reasonable cost and the limited access of utilities to their non-tradable credits may actually prevent market upsets that would trigger the widespread release of non-tradable/non-useable credits to all RECLAIM operators. Finally, if utilities are assessed a fee for their use of the non-tradable/non-usable credits in advance of the 12-month price trigger being reached, the proceeds would be available to the District to facilitate voluntary NOx emission reductions

Response 8-2

The comment expresses support for the accessibility to non-tradable credits in the event of a market upset. SCAQMD staff has provided safety valves to provide access to the non-tradable/non-usable account and to the Regional NSR Holding Account in the event of the 12-month rolling average threshold price trigger being reached or in a State of Emergency. Other stakeholders do not believe there should be a cost to access such credits. Please see response 7-1.

Comment 8-3

Sunset of Non-tradable/Non-usable Holdings. The Cities understand that SCAQMD proposes to discontinue the non-tradable/non-useable holdings in the year 2022. Given the uncertainty presented by increased integration of renewable resources and regional electrification, the Cities ask SCAQMD to provide for continued utilization of the non-tradable / non-useable holdings, at least for municipal utilities.

Response 8-3

The comment requests that the non-tradable/non-usable holdings to be provided in perpetuity to municipal utilities. The staff proposal intends to submit the non-tradable portion of the shave into the SIP, and if they were held indefinitely and could potentially be accessed, they would never be available for SIP emission reductions. However, for new electric generating facilities subject to multi-year NSR holding requirements, the shaved portions of holdings will go into the Regional NSR Holding Account. This account will hold the RTCs for NSR purposes in perpetuity and will provide relief to these facilities, while setting aside some RTCs for future uncertainty in the electricity market. Staff intends to include a resolution to closely monitor the impacts of potentially increased electricity demand and renewable penetration on NOX emissions, and will propose RECLAIM program adjustments to the Governing Board if needed.

Comment 8-4

Regional NSR Holding Account, Compatibility of Dual Purposes. The Cities appreciate that SCAQMD is proposing alternatives that would ease the NSR holding requirement burden and also provide additional RTCs in the event of an emergency. However, it is not clear that both purposes can be simultaneously served, given the amount of RTCs that SCAQMD proposed to allocate to the account. The Cities ask that SCAQMD clarify how the account can be available for emergency use by all electrical generating facilities, without jeopardizing the ability of new facilities to make the NSR holding demonstration.

Response 8-4:

The commenter has concerns with how the Regional NSR Holding Account will be able to support the NSR requirements for facilities if the account is accessed by all electric generating facilities in a State of Emergency. The proposed rule language clarifies how the NSR Regional Holding Account would be implemented, and that it would be available to all electrical generating facilities under a State of Emergency. There is no issue with using such RTCs for dual purposes. The NSR holding requirements cease after the compliance period ends, and if they are not used to offset actual emissions, the credits become available for other purposes. This is the situation as it exists today as RTCs can be sold after the compliance period ends.

Comment 8-5

Additional entities or authorities should be allowed to declare the presence of an energy emergency at both a regional and local level. Many emergencies requiring local power generation may exist within the boundaries of a city and state or regional authorities may not be able to investigate and make the necessary declaration quickly. Local authorities, such as a City Manager or Mayor, should also be allowed to make a declaration that would allow for the release of RTCs from the Regional NSR Holding Account.

Response 8-5

The commenter asks why the State of Emergency declaration can only be made by the Governor and not by a local government official. Staff believes that a major power crisis would warrant this type of declaration and that local emergencies can be handled within the framework of the RECLAIM program, such as purchasing credits in the market to reconcile these emissions. If there is a necessity for credits, such an exceedance of the 12-month rolling average RTC price threshold trigger, then the non-tradable credits could be made available. See Response 7-5.

Comment 8-6

It is unclear how access to RTCs would be granted or how competing applicants would be prioritized by SCAQMD to receive RTCs. SCAQMD must further define its role in the process of granting access to the Regional NSR Holding Account if the Cities are to be assured that credits are available not only for the NSR holding demonstration, but also for easy access in case of an emergency.

Response 8-6

The comment requests for further definition as to how the Regional NSR Account credits will be prioritized for distribution. If the Governor declares a power emergency, the current year non-tradable/non-usable RTCs held by electric generating facilities can be used to offset emissions after exhausting their own usable RTCs, unless they sold any part of their RTC holdings for the subject compliance year. If an eligible facility has exhausted their non-tradable/non-usable RTCs, it may apply for use of the accumulated RTCs in the Regional NSR account. The supply of emergency annual RTCs will be sufficient to handle a short term crisis. If the crisis is prolonged such that the demand for emergency RTCs is greater than the supply, there will be time to return to the Governing Board to make program adjustments. The staff proposal includes provisions to report to the Governing Board and proposes a plan for RTC distribution and other program adjustments when the State of Emergency access is triggered.

Comment 8-7

The Cities ask SCAQMD to clarify how the Regional NSR Holding Account would affect the way in which new power producing facilities would manage the remaining RTCs listed in their facility permits, with respect to the Rule 2005 (f) holding requirement. Ideally, provisions to accommodate the holding requirement would also allow facility operators to sell the remaining unused RTCs listed in their permit in advance of compliance year closure. We also ask SCAQMD to give consideration to the same discretionary use of the Regional NSR Holding Account by municipal utilities that is proposed within this letter for the non-tradable/non-useable holdings.

Response 8-7

The comment requests for further clarity on how the Regional NSR Account will affect how the RTCs are reflected on the facility permits. Amounts of NSR holdings going into the Regional account year by year is listed in Rule 2002 for each facility. On the facility RECLAIM permits, Section B would still contain the usable/tradable and non-usable/non-tradable amounts, but the permit condition will refer to Rule 2002.

The commenter also request the same use of the credits from the Regional NSR account to the non-tradable/non-usable holdings. For newer electric generating facilities, the non-tradable/non-usable holdings and the holdings in the Regional account are essentially drawn from the same pool of credits. For every portion of the shave designated as non-tradable/non-usable, the RTCs will go into the Regional account the following year, instead of being submitted into the SIP. Facilities would have access to the Regional account portion for offsetting annual emissions if a State of Emergency is declared. The non-tradable credit portion for newer facilities would not be available for sale, however.

Comment Letter # 9 – Eco Services Letter Dated August 28, 2015

Comment 9-1

Eco Services does not support a program that leaves no reasonable means of complying. We support revisions to the RECLAIM program that rely on implementation of feasible and cost-effective controls. Sources that can implement BARCT can and should do so as a first step towards additional reductions. We strongly urge the SCAQMD to consider this approach which will result in a reduction of NOx emissions based on cost-effective controls which will not cripple the RECLAIM trading program and leave smaller emitters no real cost-effective option for compliance. If the SCAQMD pursues the across the board shave, it will effectively be imposing cost-effective requirements on the BARCT sources but not considering cost-effectiveness at all for non-BARCT sources. Eco Services believes that is inequitable and inappropriate.

If the SCAQMD does pursue an across the board NOx shave, Eco Services recommends that the changes to RECLAIM include some type of measure to limit the costs of NOx credits in addition to the current $15,000 per ton annualized average cost, particularly for small emitters. An equitable rule should provide the regulated community with a cost-effective means of complying. We request that the SCAQMD somehow provide a ceiling on the financial impact it will have on RECLAIM participants in terms of cost-effectiveness. BARCT sources will be subjected to cost-effective controls. Similarly, the financial impact to non-BARCT sources should also be based on cost-effectiveness.

It is our understanding that Non-Tradable/Non-Useable allocations will be issued to emitters, and that these “safety valve” allocations can be used as compliance instrument when the average cost of annual NOx RTC exceeds $15,000 per ton (or $7.50 per pound). However, we believe that the time for cost averaging should be significantly shortened to prevent the repeat of situation similar to year 2000 when the value of annual NOx RTC went far above the $7.50 per pound threshold. Also, additional safe guards should be considered to prevent non-compliance for non-BARCT sources if the NOx RECLAIM market fails such that no NOx RTCs are available to be purchased.

Response 9-1

The comment expresses concerns about the effect of the shave on a facility, such as Eco Services that does not have equipment subject to BARCT. Staff appreciates your comment and acknowledge all your efforts in reducing SOx emissions with the installation of the wet gas scrubber at your facility. We believe that if BARCT reductions are achieved in 2022, there should still be a comparable margin in the market between the allocation cap and the actual emissions as there is today. The current market has about a 28% margin, while in 2022 the market should have about a 23% margin if BARCT controls are installed. The implementation schedule is over several years, so the full magnitude of the shave would occur gradually. As the allocation cap decreases, the price of RTC is expected to rise. Despite this, there is a safety valve that would allow for more RTCs to be accessed in the event that the 12-month rolling average threshold price trigger is reached. The commenter also has concerns of the financial impact to facilities facing a similar situation. Please refer to the socioeconomic report. The commenter also makes reference to a prior comment letter submitted on April 27, 2015 which refers to the price of purchasing credits based on the current market value. We acknowledge that at the current price of credits of around $100 per pound, the cost of purchasing credits after the shave to offset annual emissions would be in the neighborhood of $2.6 million for your facility. Your facility is included as part of the shave because it is among the top 90% of RTC holders and the RECLAIM program will have some structural buyers.

Comment Letter #10 – Charles Timms, Jr. Letter Dated September 17, 2015

Comment 10 - 1

We have identified some additional rule language that would need to be amended to facilitate our proposal that power plants be provided with quicker access to non-tradable/non-usable NOx RTCs, and/or access to RTCs in the Adjustment Account, if needed to cover annual emissions. This additional language will ensure that the relevant RTCs are only credited to the SIP on a year-by-year basis to the extent they are not needed for power plant compliance purposes. See Attachment 1 to this letter.

In addition, the Cities support the proposal of the Los Angeles Department of Water and Power to expand the emergency provisions in the staff proposal to allow power plants to access RTCs in the Adjustment Account if an energy emergency alert is declared by the relevant electrical "Reliability Coordinator." See Attachment 2 for proposed rule language.

Proposed Amended Rule 2002(f)(1)(J) shall be amended to read as follows:

"The NOx RTC adjustment factors for compliance years 20019 through 2021 shall not be submitted for inclusion into the State Implementation Plan until the adjustments have been in effect for one full compliance year. The 2022 NOx RTC adjustment factors shall not be submitted for inclusion in the State Implementation Plan until 12-months after the adjustments have been in effect for one full compliance year. At the end of each compliance year reconciliation period from 2022 and each year thereafter, the Power Producing Facility shall surrender unused non-tradable RTCs to the District for inclusion into the State Implementation Plan."

Proposed Amended Rule 2002(f)(5) shall be amended to read as follows:

"During a State of Emergency as declared by the Governor or an Energy Emergency Alert as declared by the Reliability Coordinator, the Executive Officer will allow Power Producing Facilities access to Adjustment Account RTCs for the purpose of compliance with the annual emissions. ~~These available RTCs will be limited to those that are in excess of those specified for use in paragraph (f)(4).~~ The amount and distribution of the RTCs will be determined by the ~~Executive Officer~~ Power Producing Facilities based on the ~~impact that~~ amount of energy they produce during the State of Emergency ~~has on the RECLAIM program~~ or the Energy Emergency Alert."

'Reliability Coordinator' means the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System as defined in the North American Electric Reliability Corporation Glossary."

Response 10-1

The commenter has suggested that additional rule language be added to ensure that unused RTCs for emissions compliance from electric generating facilities are submitted into the SIP on a year-by-year basis. The proposed rule language establishes the mechanism by which the non-tradable and Regional NSR accounts are handled. The non-tradable account is the yearly shaved amount of RTCs. The rule language states that after one full compliance year the credits will be submitted into the SIP. For the first year of the shave, the non-tradable account can be accessed if the 12-month rolling average threshold price trigger is reached or if there is a State of Emergency. For electric generating facilities with continual NSR requirements, the non-tradable balance can be used for NSR holding purposes, and subsequently will become the portion that will fund the Regional NSR account for the same purpose. However, the RTCs may be used for compliance with annual emissions and will become usable if the price trigger is reached or a State of Emergency is declared. Existing electric generating facilities will also have access to their non-tradable/non-usable RTCs in a State of Emergency, as well as the Regional NSR Holding Account. If the non-tradable account is accessed, the following year's permit will be adjusted accordingly.

The commenter also provided some suggested rule language that echoes the same comments from the previous comment letter regarding the designation of a State of Emergency by someone other than the Governor. As stated in the response to comment 7-5, the safety valves that are proposed by staff are sufficient to ensure that there will be available credits in the event of either a shortage of credits or a major power crisis as declared by the Governor. Staff does not support allowing the Reliability Coordinator to dictate access to the Regional NSR account because an "alert" is not a true State of Emergency requiring extraordinary measures.

Comment Letter #11 – Southern California Edison No Date

Comment 11-1

The shave should drive sources towards BARCT

The shave, as proposed, would constitute a 53% reduction in the total number of RTCs in the market. 67% would be taken from the refinery sector while 47% would be taken from the non-refinery sector, including electric generation facilities. While this would be better than an outright across-the-board shave, it still would trigger costs for the electric generation sector that would have no commensurate impact on reducing air emissions. The electric generation facilities are already at Best Available Control Technology (BACT) with no existing opportunity to reduce emissions (other than curtailing operation, which is not feasible for electric generation facilities since electric demand will dictate operating times). While there is recognition there will have to be some reduction of RTCs from electric generation facilities, the shave should cause facilities not currently at BARCT to install better controls. With the proposed percentages, the costs will disproportionally impact facilities that are already at BACT and result in a subsidization by those at BACT of facilities not yet utilizing the best controls.

Response 11-1

The commenter states that there will be cost impacts to electricity generating facilities when there is no reduction in emissions from these sources. While we recognize that most of the equipment used by the electric generation sector is at BARCT or BACT, the proposed shave affects the top 90% of RTC holders and is necessary to obtain the highest amount of feasible reductions to meet SCAQMD's attainment goals. Note that most electricity generating facilities hold a significantly more RTCs than their actual emissions, and that staff is proposing resolution language to monitor trends in electricity demand and propose program adjustments if necessary. The staff proposal has several safety valves that can address certain issues that are specific to the electrical generating sector, such as relief from yearly NSR holding requirements.

Comment 11-2

The proposed shave amount on the Electric Generation Facilities in effect caps the amount of fuel we can use

As stated above, SCE's electric generation facilities are already at BACT or BARCT, with no currently feasible opportunity, from a control standpoint, to reduce emissions further. With no advancements in control technology, the only way to further reduce emissions is by curtailing operation (i.e. limiting fuel usage). Thus, if no credits were available for purchase on the open market, which is a possibility given the proposed size of the shave, the only way to stay in compliance would be by reducing fuel usage.

It should also be noted that under the California Health & Safety Code for market-based programs [§39616(c)], a program must not result in disproportionate impacts to stationary sources in the program as compared to other permitted stationary sources not in the program. A typical permitted source not in the RECLAIM program is subject to rule-based command and control regulations. Were SCE's facilities not in the RECLAIM program, command and control regulations would require BACT concentration limits with no further limits on operation or fuel use, unless such further limits were agreed to for PTE or CEQA limit purposes. However, because the facilities are in RECLAIM, not only are they subject to BACT, but also to the holding requirement and the potential surrender of RTCs. The result is that if there aren't enough RTCs in the market, this proposed shave would effectively cap fuel use. By setting a concentration limit as well as a fuel use limit, this proposed shave would go beyond command and control regulations.

Response 11-2

The commenter states concerns with a potential shortage of credits as a result of the shave. As stated in the previous response, there are safety valves in the current rule and also in the rule proposal that would prevent this condition from occurring. For example, existing electric generating facilities would have access to non-tradable credits in the event that the 12-month rolling average threshold price trigger is reached or if a State of Emergency is declared. New electric generating facilities (in RECLAIM after October 15, 1993), would have access to a Regional NSR Holding Account to relieve them of NSR holdings requirements that often require holding excess credits at the potential to emit level, even though the actual emissions are far below this level. In addition, in the event of a power emergency, all electric generating facilities would have access to the Regional NSR account for credits used to offset these emissions during an emergency.

Comment 11-3

The amount of the shave could have impacts on grid reliability during emergency situations.

The current proposal contemplates what amounts to a 53% shave in the existing RTC market. While action must be taken to reduce current NOx emissions, this action must not result in a situation where generating facilities are unable to operate during emergency situations. The electric grid is a complex, interrelated system. All components work together to generate and ultimately distribute electric power to end users. If, for example, a major transmission line were to go down, there would be an immediate need for local, dispatchable generation to begin operating. If these facilities don't have sufficient RTCs to operate in these circumstances, the system would be faced with energy resources that could not be operated under SCAQMD rules, which would result in load curtailment. Because of the complexity of the system, there is no bright line that can be drawn. The District must therefore exercise caution and not bring about a market that is incapable of responding to emergency situations.

Response 11-3

The comment states that access to additional credits should be realized in a faster timeframe for unforeseen situations where emergency power generation may be necessary. Non tradable/non-usable RTCs are proposed to be accessed immediately if a State of Emergency is declared. Please refer to the response to Comment 11-2. Despite this, a facility would still have some time to reconcile all of its emissions at the end of a compliance year quarter, plus the reconciliation period.

Comment 11-4

Changes to the RATA testing requirements are supported

Thank you for meeting previously with SCE and DWP on this matter and recognizing that there was a legitimate need to change the rule language regarding postponement of RATAs. In the past, SCE has experienced multiple incidents where equipment has failed in the quarter in which a RATA was due, and found that the District's options for RATA postponement were impractical. With no reasonable alternative to postpone testing, and in order to avoid enforcement, the facilities were forced to petition the SCAQMD Hearing Board for variances. SCE believes the proposed language addresses this issue and now provides a legitimate alternative for RATA postponement without variance relief.

While we fully support the option presented, we are requesting an increase of the 14 unit operating day extension to 30 unit operating days. The main concern is with SCE's Pebbly Beach Generating Station on Catalina Island. Due to its remote location, weather related delays of transportation options to the island, and the high work load schedule of our source testing firm, it can be difficult to organize a RATA test in a short timeframe. The testing firm must separately schedule a time to barge its equipment out to the island, and if power demand on the island were high, the engines may need to run as soon as possible when they return to service, which could impact the test protocol This is especially true for the cleaner engines, as they must operate more frequently in order to comply with facility-wide emission limits. If the source testing firm could not schedule a visit to the island and the engines had to operate to support the power demand, 14 operating days might not be enough time to complete an appropriate RATA. As an alternative, if staff is not open to extending the 14 unit operating day window, SCE suggests having an equivalent operating hour limit. This could give the facility more time to schedule a test without increasing the overall operating time of the unit. Whether there are 14 days or 30 days to complete a RATA, a facility has plenty of incentive to complete the RATA as soon as possible so as to minimize the use of missing data procedures. We ask that the District consider this extension. But other than this amendment, we fully support the rule language as presented by the District and we appreciate the work done by staff to address this issue.

Response 11-4

The comment requests additional time for the extension of postponed RATA testing from 14 operating days to 30 operating days. The operating days do not have to be consecutive days so the total calendar days since the re-firing could be longer than 14 consecutive days.

Comment 11-5

SCE Supports the adjustment account for compliance with Rule 2005 Subdivision (f). Existing USEPA interpretation of the NSR requirements hold that a facility in RECLAIM must obtain sufficient RTCs at the beginning of the calendar year to cover the total potential to emit (PTE) for the year notwithstanding that most facilities do not operate at or near their PTE. This results in a substantial procurement of RTCs that are necessarily bought at a time they are most expensive, but if not used are then sold off when they are of little value. Further, there is no environmental benefit created by what is, in effect, an over-procurement of credits. SCE supports the proposal by the District to create an adjustment account that would cover this RTC requirement. It would eliminate the costly procurement of RTCs beyond what is really needed to cover actual emissions and, quite simply, it makes sense. We urge the District to continue to seek EPA concurrence with this proposal.

Response 11-5

The comment expresses the support for the establishment of the Regional NSR Holding Account. We appreciate your support for these provisions affecting newer electric generating facilities with burdensome NSR holding requirements.

Comment Letter #12 – GE Capital & Inland Empire Energy Center Letter Dated September 22, 2015

Comment 12-1

Inland Empire Energy Center, LLC, a wholly-owned subsidiary of General Electric (GE), is the permit holder for the Inland Empire Energy Center (IEEC). GE purchased all NOx RTCs required for the IEEC instead of having them purchased by IEEC, LLC. The GE RTC account is, and always has been, 100% dedicated to the IEEC. Thus GE's NOx RRTC account should be designated as an Electric Generating Facility (non-refinery) account for purposes of the allocation shave. We therefore request that the GE RTC account be correctly categorized as an Electric Generating Facility (non-refinery) account in Table 8. Currently, GE is categorized as an "investor".

Response 12-1

The comment requests for the Investor account that is associated with Inland Empire Energy Center only to be categorized as an electric generating facility subject to the shave for the non-refinery sector. SCAQMD staff has reviewed the information you submitted and we agree that the investor account is associated with this electric generating facility only. The updated list of facilities will reflect the categorization of the investor account as a facility among the electric generating facilities affected by the shave. Table 8 of Rule 2002 will also be updated to reflect this change.

Comment Letter #13

Comment 13-1 The Shave for the Program Should be a Minimum of 14.85 tpd

We do not agree with the decision to reduce the total shave amount by 0.85 tpd, from the required 14.85 tpd to 14 tpd. California's Health & Safety Code is abundantly clear that trading programs must "result in an equivalent or greater reduction in emissions at equivalent or less cost compared with current command and control regulations. . . ." Cal. Health & Safety Code §39616. In reviewing the materials produced through this rulemaking, the Best Available Retrofit Control ("BARCT") assessments show that a BARCT-equivalent program would result in 14.85 tpd fewer emissions. Accordingly, to comply with Health & Safety Code section 39616, the shave for the RECLAIM program must also be at least 14.85 tpd. We also suggest shaving even more from the program given the large size of the "black box" that must be reduced to meet ozone standards.

Response 13-1

SCAQMD staff understands the commenter's request for as many reductions as possible to be able to meet the attainment goals of the region. The reason that the overall RTC reduction is 14 tons per day and not more is to account for some BARCT uncertainties that arose in the refinery boiler and heater category. Staff and the consultant hired to do an independent BARCT assessment had some reasonable, but different engineering and cost assumptions which resulted in an adjustment to the staff proposal to account for this uncertainty.

Comment 13-2 The Implementation Schedule is Weak

We are deeply concerned that the schedule for implementation for the shave is too protracted. *See* Slide 4 of the Staff Presentation. Given recent difficulties in meeting various air quality standards, including the 1997 and 2006 standards for fine particle pollution ("PM2.5"), it would be prudent to move up some of the latter year reductions. In fact, we suggest amending the schedule to the following to ensure reductions on the front end in time for compliance with
Standards: 2016: 5tpd, 2018: 3 tpd, 2019: 3 tpd, 2020: 2 tpd, 2021: 1.85 tpd.

Response 13-2

Staff agrees with front loading some of the RTC reductions and has proposed a 4 ton per day reduction in 2016. The implementation schedule serves two purposes. The first is to address the SIP commitments to EPA regarding the contingency measure for 2016. The second is to ensure facilities have adequate time to install controls if that is how they choose to comply.

Comment 13-3 The District Should Not Establish a NSR Set Aside

Health Advocates do not support the implementation of a District-operated set-aside for New Source Review ("NSR") holdings. There is no basis for the District to undertake this task. In fact, this provision exists to ensure the program does not erode air quality progress in the region. We think this is a necessary safeguard, and we have not heard a compelling reason why the District should take on this duty. Industries have complied with this provision for decades, and it makes sense to continue to place this duty on industry.

Response 13-3

The commenter disagrees with the staff proposal to offer the Regional NSR Holding Account for electrical generating facilities. The staff proposal aims to reduce the total allocation of the RECLAIM universe by over 53%. This is a very substantial reduction, much more so than the 22.5% reduction that resulted from the 2005 amendments to RECLAIM. Electrical generating facilities are in a unique situation in that they are all at either BARCT or BACT. In addition, the newer electric generating facilities have to meet the NSR holding requirements every year at the potential to emit level, even though the actual emissions are far below this level. While the staff proposal will shave those electric generating facilities among the top 90% of RTC holders by 49%, the Regional Account would provide some relief from their NSR holding obligations and help to maintain a functioning market in the event of a power emergency. This Regional Account would account for a small fraction of the overall proposed RTC reduction, which is designed to achieve BARCT-equivalent levels of emissions across the program.

Comment 13-4 The California Environmental Quality Act Analysis Should Examine a Command and Control Alternative

It is important that the Governing Board and the public receive full information on the environmental landscape of this action. In particular, through the California Environmental Quality Act ("CEQA") process, an assessment of a Command and Control alternative will be important to understand how quickly desperately needed reductions could be implemented in the South Coast under a regulatory program requiring implementation of readily available technologies, many of which have not been installed at the largest NOx emitters in the South Coast. Under the currently proposed approach, clean up would be protracted for many years as the shave is implemented. A Command and Control Alternative would achieve reductions sooner than this compliance schedule.

Response 13-4

The commenter requests that a command and control alternative should be evaluated by CEQA. The purpose of the RECLAIM program is to allow emission reductions equivalent or greater to command and control at an equivalent or less cost. The BARCT analysis analyzed the technologies available to effect emission reductions that are cost effective and that are in compliance with the California Health and Safety Code. The actual control technologies to meet BARCT would be the same under command and control as assumed in the Project in the CEQA document, so the environmental impacts would be the same.

Comment 13-5

The claims of industry lobbyists that the IYB credits are appropriately priced are not true. In fact, like the short term credits, these credits are exceptionally low. Even with a more than doubling of the IYB prices in 2014 compared to 2013, these credits are only 18% of the $609,187 cost established by the District pursuant to section 39616(f) of the California Health & Safety Code, which is set to ensure credit prices do not go too high. That the failure of these IYB credits to even approach 1/5 of the District's ceiling for credit costs just bolsters the excessive number of credits in the NOx RECLAIM system. Overall, the evidence conclusively suggests that the credits are not priced correctly to push for pollution reductions at a level commensurate with what command and control would achieve, which is borne out in the District's BARCT assessments.

Response 13-5
Comment noted.

Comment 13-6 The Shave Approach Must Ensure Reductions from Refineries and Electric Generating Facilities.

The evidence presented by the District in this rulemaking indicates that refineries have used the NOx RECLAIM system as a shield from actually installing pollution control equipment like Selective Catalytic Reduction ("SCR"). Given this past behavior, we suggest that the best path forward is that refineries be taken out of the NOx RECLAIM program and be required to install pollution control equipment.

Response 13-6

The comment states that refineries should be removed from the RECLAIM program to force the installation of control equipment. As stated in the previous comment, the staff proposal is for a 53% overall RTC reduction from the RECLAIM universe. The refinery sector would experience a 66% RTC reduction. Staff believes that there is a sufficient impetus in the staff proposal to effect cost effective control technology installations at these facilities.

Comment Letter #14 Arnie Smith Email Dated August 11, 2015

Comment 14-1

At this point, we are probably one to two months away from having finalized NOx RECLAIM rules. Then, we are only another two months from the beginning of the first compliance year. There will be inadequate time for project development with any results in 2016/2017 - even for simpler scopes like burner replacements in existing heaters or catalyst upgrades in existing SCRs. But, new scrubbers or new SCRs would not be able to provide any mitigation benefit until 2018/2019.

The ongoing SOx RECLAIM Program had a gap of 26 months from the end of rule-making to the beginning of compliance - which would allow for some mitigation to be realized in the first compliance year. A three year gap would have insured an even stronger result.

A three year gap between rule-making and the first compliance year for NOx RECLAIM would have provided a better start for a real NOx reduction.

Response 14-1

The commenter expresses his concern that the proposed implementation schedule for the shave would provide inadequate time for projects to be completed and provided a reference to a document from the Association for the Advancement of Cost Estimating (AACE) that many engineering, procurement, and construction (EPC) firms use for designing their projects. The commenter uses the reference to illustrate that it takes many months of lead time and up to two to three years for emission reduction projects to be installed. Staff understands that there is a lead time associated with any construction project, but believes that the initial 4 ton per day reduction in 2016 would be satisfied by removing unused RTCs while still being able to provide the market with sufficient credits until further reductions in the allocation cap are realized. There is currently about a 28% margin from the allocation cap and the actual emissions. With a 4 ton per day reduction, it is anticipated that there would still be sufficient credits in the market to cover actual emissions. By 2018 when the next portion of the shave will be effective, several smaller projects would likely be installed, so when 2019 is reached, those larger projects that the commenter has referred to would be in place and would result in emissions under the allocation cap.

Comment Letter #15 Karl Lany Email Dated August 20, 2015

Comment 15-1

Thanks for taking the steps you have to accommodate Rule 219 boiler technology into the proposed RECLAIM amendments. After giving the concept more consideration, I continue to question the proposed requirement that such boilers be subject to testing requirements in order to qualify for RECLAIM reporting factors that reflects certification standards.

The entire SCAQMD program for certified diesel engines rests upon certification standards and excludes any emissions testing. It makes sense that the benefits of certification (exclusion from unnecessary emissions tests) that are extended to process unit diesel engines in RECLAIM would also be extended to permit exempt natural gas boilers that are subjected to a similar certification program.

I sincerely hope that SCAQMD reconsiders its proposed testing requirements for Rule 219 boilers in RECLAIM and instead provides a more practical solution that reflects the legitimacy of its boiler certification program.

Response 15-1

The commenter requests a reconsideration of the source testing requirements of small, unpermitted boilers in the staff proposal for usage of a lower emission factor for reporting Rule 219 equipment emissions. See Response 6-2.

Comment Letter #16 George Piantka Email Dated August 14, 2015

Comment 16-1

In Rule 2005, will there be proposed language to address annual holding limit requirements for a facility like Walnut Creek?

Response 16-1

The comment asks for proposed language for the affected facility. Staff is proposing to list the actual NSR holdings going into the Regional account year by year in Rule 2002 for those affected facilities. On the facility RECLAIM permits, Section B would still contain the usable/tradable and non-usable/non-tradable amounts, but the Regional account holdings will refer to the Rule 2002 as part of the permit conditions.

Comment 16-2

The financial impact to a new facility like Walnut Creek is different than an existing RECLAIM facility or new plant at an existing RECLAIM facility. In satisfying NSR (unlike a legacy RECLAIM facility), IYB Cycle 1 and 2 RTCs were purchased from the market. Demonstration that we satisfied the RTCs for annual NOx PTE was not only necessary for the Permit to Construct and annual Permit to Operate but also for the financing of the WCEP. We would now represent that the asset has lost the equivalent of 47% of its NOx IYB RTCs at the current rate of say $115/lb-yr and address the means to which we can demonstrate our continued holding and/or access to these RTC for the lenders. While not obvious, the financial implications are different than a facility that has relied on an existing RECLAIM account or the ability to reconcile its emissions for the respective year. It is the difference between losing the unrealized value of IYB RTCs in a legacy RECLAIM account versus the purchase, shave and possible replacement of them at the new market condition (or from the Regional NSR Holding Account?) to meet its PTE. This is one of the reasons why we believe WCEP should be exempt from the shave.

Response 16-2

The comment expresses concerns with the shave and its effect on a new facility that will continue to have NSR holding requirements every year. Staff acknowledges this situation for new electric generating facilities and the proposal includes provisions that would provide some relief for the NSR holding requirements with the establishment of the Regional NSR Holding Account.

Comment Letter #17 Chuck Casey Email Dated September 24, 2015

Comment 17-1

The list as provided in table U.1 needs to be audited with a full explanation of who is included or excluded and the reason for each. The NOx shave percentage adjusted for non-refinery RTC holders' weighted reduction, currently 47%, would require adjustment if the list changes.

Response 17-1

The commenter requests for a clarification on which electric generating facilities are part of the proposal for the shave and if cogeneration facilities are to be considered electric generating facilities for inclusion in the shave. SCAQMD staff has taken your comments into consideration and acknowledges that all electric generating facilities were included into the shave, even those under the 90% RTC Holders cutoff so that those with NSR holding obligations would be able to use the Regional NSR Holding Account. Upon further consideration, staff has removed those electric generating facilities that are under the 90% cutoff for RTC holders from the list of facilities for the shave.

Attachment to Appendix Z

Comment Letters #2 - #17

NORTON
engineering

112 Main Road, 2^{nd} Floor
Montville, NJ 07045
Office: 973-394-9330
Fax: 973-394-9336
www.nortonengr.com

James P. Norton
President & CEO
Office: 973-394-9330 x200
Mobile: 201-314-2038
jpnorton@nortonengr.com

August 10, 2015

Philip M. Fine, PhD
Deputy Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765-4178

Comments on Preliminary Draft Staff Report
Proposed Amendments to Regulation XX
Regional Clean Air Incentives Market (RECLAIM)
NOx RECLAIM – SCRs for FCCUs
Document No. 14-045-7

Dear Mr. Fine,

We have completed a first pass review of the above captioned report's discussion of SCR applications to district SCRs and have identified several misstatements and/or misunderstandings of the information provided by our company, under contract from SCAQMD, which may have material impact on the conclusions drawn by staff in the report. It is my intent in this letter to clarify the most glaring misstatements/misunderstandings of the information we provided to the district both in our final report (Doc. No. 14-045-4, Nov. 26, 2014) which summarized the data on a non-confidential basis, and the details provided on a confidential basis to the district and individually to each of the refineries.

We stated, quite clearly, in the final report and in subsequent discussions with staff, that we agree that 2 ppmvd (3% O_2) NOx emissions is a justifiable emission level for SCR applications to FCCUs, Fired Heaters, Boilers, Gas Turbines and TGU/SRUs, with caveats. While a few existing units can meet this guideline under current operating conditions, many more, similarly designed units have not demonstrated similar low emissions capabilities. With the exception of Gas Turbine installations (which have an equivalent emission level of 6 ppmv @ 3% O_2) most low emission SCRs in service today, being built today and even those being designed today carry manufacturer's guarantees to meet a NOx limit of 5 vppm @ 3% O_2. In spite of the limited number of units (other than gas turbines) operating at or below 2 vppm NOx, we believe that it is possible to achieve these levels, but to guarantee long term reliable performance (refineries typically operate 24/7 for periods of 4 to 6 years) it is prudent and quite possibly necessary to design future SCRs to increase residence time, improve NH_3 distribution, improve overall flue gas flow distribution, add catalyst, etc. SCAQMD staff agrees with this concept but we have strong disagreement as to how much change from current SCR designs will be required to achieve the sought after NOx reductions not only on day one but at the end of year one and year five and beyond.

NEC's engineers have extensive experience in process development, equipment development and project development for the refining and petrochemical industry in the manufacturing and air pollution control areas. The experience level of the engineers who completed our technology and project cost evaluations is 51, 37 and 8 years. It is exactly this experience base, and past successful work with the district, that caused you to look to NEC to develop "cost guidance" for evaluating the refining sector. We find it very surprising therefore, that staff essentially ignored our recommendations and continued to use what we feel are unrealistically low costs for NOx control projects for district refineries.

Comments on FCCU SCR Costs

Appendix F presents a review of NEC's analysis for FCCU SCR costs by SCAQMD staff. It concludes that NEC's estimated costs for NOx control are excessive and gives the following reasons for this assessment:

- NEC recommends using three catalyst beds and designing for superficial gas velocities of 10 ft/sec vs SCR vendor proposals which have less catalyst and 20% higher superficial velocities.
- NEC conditions budgetary quotations from manufacturers for the accuracy of the quote, the accuracy of the project basis and for the application of refining industry standards for construction of the equipment. This is characterized by staff as: "Adding a "mark-up" factor, or a bid conditioning factor of 1.35 to increase the costs".
- NEC includes the cost of installation of the SCR in its estimate to arrive at a direct material and labor cost for the SCR component of a project at 75% of the equipment cost. Characterized by staff as: "Adding another 75% increase in labor to the costs of the manufacturer's SCR.".
- NEC used incorrect FCCU feed rates in developing comparisons to AQMD PWVs.

The following paragraphs address each of staff's objections and provide additional information and clarifications to address what we perceive as staff's misunderstanding of the information presented in our final report.

Basis for Catalyst Addition and
Velocity Reductions vs Vendor Budget Quotes

All FCCU SCR catalyst beds are in the range of 3 - 4' deep, all are prone to plugging by catalyst and/or ABS and all have limitations on allowable pressure drop, so superficial velocity is a good basis for comparison between units. The district has three operating FCCU SCRs. All units have two catalyst beds and operate at superficial gas velocities in the range of 8 to 13 ft/sec. Two of the three units, operating at superficial velocities of 12 and 13 ft/sec do not achieve emissions of 2 vppm @ 3% O_2. The other unit, highlighted in the draft report, achieves less than 2 vppm @ 3% O_2 operating at a superficial velocity of 7.7 ft/sec. The "good" unit is operating with inlet NOx levels which are 50%

of design or lower and at lower than design flue gas flows. There are several ways to bring the two "non-performing" units into compliance with the revised standard, each with different costs and different overall performance impacts. NEC was not commissioned to do an evaluation of individual units and propose improvement options, but rather to make an assessment of what it would take, cost wise, to reliably achieve the 2 ppmv limit for grass roots SCR installations. Based on the experience of operating units in the district, and our direct experience with FCCU units for other clients (due to confidentiality agreements we cannot divulge client identities and specific locations) reliably achieving 2 vppm NOx emissions in an FCCU over a five year run will require the addition of catalyst and will be designed for superficial velocities of 10 ft/sec or less. Considering that SCR catalyst vendors have not developed and guaranteed a specific SCR design for 2 ppmvd @ 3% O_2 NEC feels that it is prudent to assume that a third bed of catalyst (SCR or ASC) and cross section designed to achieve a maximum superficial velocity of 10 ft/sec is sufficient to characterize the most likely cost of a SCR unit capable of achieving 2 ppmvd in a typical refinery FCCU environment. *The impact of the increased cross sectional area and the addition of a third bed of catalyst on the cost of an SCR installation has been overstated by district staff as a 284% increase in catalyst volume over manufacturer's estimates. The increase over manufacturer's budget estimates/proposals is actually 92%, one half of staff's reported delta.*

Staff's SCR Design Comparison Did Not Accurately Reflect NEC's "Typical" FCCU SCR Design

Staff used an incorrect basis for comparing NEC's typical FCCU SCR with district units in Table F.3. A revised comparison, using data from Refineries 1, 5 and 6 is shown below.

Table 1 (F. 3 Showing NEC Typical SCR)
Performance Information of Existing SCRs

	Refinery 1	Refinery 5	Refinery 6	NEC Typical
FCC Feed Rate, kBPD	95	71	84	55
SCR Inlet Flue Gas Flow, ACFS	6,585	5,525	9,685	3,848
SCR Manufacturer	1	3	2	--
No. Catalyst Layers	2	2	2	3
Catalyst Volume, ft^3	6,200	2,975(1)	6,200(5)	4,600
Design Inlet NOx, ppmv	133(2)/40-80(3)	150	35	45
Design Outlet NOx, ppmvd	--	17	6	2
NOx Measured, ppmvd	<2	15-17	5.6 – 6.4	1.5 (Est.)
Superficial Gas Velocity, fps	7.4	13.3	11.6	10.0
Space Velocity, 1/hr	3,823(6)	6,686(4)	5,624(5)	3,011
Removal Efficiency	95 - 97%(3)	89%	83%	97%

Notes:

1. Staff incorrectly stated catalyst volume as 2,391 ft^3 in Table F.3. 2,975 ft^3 catalyst volume confirmed by NEC with Refinery 5 and via review of SCR data provided by Refinery 5 to SCAQMD.
2. Design value reported as 155 ppmv @ 0% O_2. Value presented in table is corrected to 3% O_2.

3. Measured outlet NOx value of <2 ppmv corresponds to operation of unit with inlet NOx in the range indicated. Removal efficiency based on range of actual operation.
4. Staff reports space velocity value of 2,974/hr in table F.3.
5. Confidential data provided by SCAQMD staff is insufficient to calculate the catalyst volume for this unit without making the following assumption on the depth of a catalyst module which we assume to be 45". Staff used ½ of this value in Table F.3 corresponding to catalyst bed depth (catalyst element height) of 22.5". Recommend staff confirm catalyst volume with Refinery 6.
6. Confidential data on unit design and performance, provided by SCAQMD staff, used to calculate inlet volumetric flow and space velocity. Values differ from staff's entries in Table F.3.

In their review, staff is suggesting that NEC's typical SCR is overdesigned and as a result overpriced. Staff's comparisons suggest an overdesign factor of as much as 284%. We do not agree with this assessment. As can be seen in Table 1, NEC's typical SCR should be able to achieve 97% NOx reduction by virtue of the addition of catalyst at higher gas velocities than the SCR operating at Refinery 1. The typical SCR design provides an approximate 21% margin in space velocity over the Refinery 1 SCR design primarily due to the addition of a third catalyst bed. The addition of a third bed has inherent performance advantages in that it provides for partial redistribution of unreacted NH_3 and NOx versus further cross sectional area additions. If it is determined that the incremental cost of specially fabricated catalyst modules (shorter depth) is low, some further optimization may be possible to reduce SCR cost. It is worth noting that the ~21% catalyst margin will have a 12% overall TIC and PWV cost impact.

Basis of the: *"mark-up" factor, or a bid conditioning factor of 1.35 to increase the costs"*

The following paragraphs provide background for NEC's use of a 35% conditioning factor for vendor equipment quotes at early stages of projects. These concepts were discussed with SCAQMD staff during reviews of our report and in subsequent follow-up phone conversations and e-mails. Due to the extensive discussion around this topic we are mystified by staff's characterization of this "bid conditioning factor" as, and here I paraphrase, 'an undefined and therefore invalid cost increase'.

Obtaining budgetary quotations from vendors for their equipment is part of the process of developing cost estimates for any project. At the early stages of projects, or when general information is sought, vendors are not provided comprehensive design basis information and therefore do not have a complete picture of the operating envelope for their proposed equipment. In these instances, some vendors will use costs from recent projects and "factor" them to the provided process conditions, other vendors may develop estimates based on equipment designed specifically to meet the provided process conditions. In either eventuality, the vendor is providing a quality estimate with reasonable accuracy (about +/- 10%) for the specified process conditions, without providing a performance guarantee and without review of the specific codes and standards applicable to refinery installations.

As project definition improves the process basis becomes fixed, equipment sizes become more reliable, performance guarantees are finalized, and vendor quote accuracy improves. Industry experience shows that at the early stages of a project, basis uncertainty alone, necessitates the addition of a 15 – 25% conditioning factor to a vendor's budget quote, in addition to other bid conditioning factors, to account for the difference seen between early equipment bids and final, full definition, performance guaranteed, equipment bids based on a definitive project basis.

Refineries are built to a more rigorous set of standards than typical air pollution control equipment which makes projects in the refining sector slightly more expensive than typical industrial projects. Standards which will have an impact on either the SCR design, the structural support design, location of equipment, internal and external maintenance access, etc., are likely to increase Direct SCR M&L costs. At this stage of project definition a factor of 10% is added to a vendor's equipment bid to account for the cost of meeting local plant standards.

The 1.35 "mark-up" or bid conditioning factor used in NEC's cost work-up for all SCR projects (FCCU, Heaters/Boilers, etc.) is not an arbitrary factor used to inflate costs, as implied in Appendix F, but is actually the low end of a time tested and proven means to determine the actual cost of a piece of equipment after full project definition is complete, including application of local industry standards to the design of the equipment, performance guarantees are offered and firm pricing for equipment components is provided by the vendor.

Basis for: ***"Adding another 75% increase in labor to the costs of the manufacturer's SCR."***

Another cost factor discussed with SCAQMD staff, and apparently dismissed as a simple adder to make costs appear high, is the cost of actually installing the equipment supplied by the SCR vendor in the plant. The vendor does not do construction and does not quote the cost of field assembly in their quote which only covers fabrication and supply of the equipment, in this case the SCR catalyst, support frames, ammonia injection grid and the carbon steel box.

The labor cost factor used in NEC's development of project costs is applied to the SCR vendor's factored estimate to account for the labor required to install the manufacturer's equipment at the site, transportation, taxes, tie-ins, insulation, access, structural steel, etc. Installation labor for equipment can range from a low of about 30% of the equipment cost to as much as 200% of direct equipment cost depending on the complexity of the equipment, the material it is made of and other equipment specific factors. In general, low cost equipment manufactured of low cost materials have higher installation percentages than highly complex equipment made of high cost materials. As a reference point, "Applied Cost Engineering", Clark F. D. and Lorenzoni A. B.; Marcel Decker Inc., 1978, uses a factor of 2.2 times direct material costs to estimate the direct M&L cost of a fired heater installation, a factor of 3.0 times direct material costs to estimate the direct M&L cost of a pump installation and a factor of 2.9 to estimate the direct M&L cost of a distillation tower. Due to the simplicity of the SCR equipment and its use of low cost materials we have used an installation labor cost factor of 0.75 (75%) to account for physical installation of the SCR, structural steel, fit-up of ducting, connection of piping, foundations, excavation, instrumentation, insulation, equipment storage, etc. This factor does not account for any costs associated with: demolition of existing equipment, modification of existing equipment, labor inefficiencies attributed to working in an operating plant, relocation and/or modification to underground utilities, piping, piping supports, ammonia storage facilities, control system additions, instrumentation wiring, conduit, power wiring, area paving, area lighting, area utilities, safety facilities, sootblowers, etc.. The cost of these items is rolled up into the overall TIC factor applied to escalate SCR M&L costs to a total project cost.

TIC Factor

SCAQMD staff disputes NEC's use of a TIC factor of 4.5 to convert direct M&L costs for the SCR into TIC for the SCR PROJECT. This factor is a reasonable estimate for project items not specifically identified in the direct M&L costs (indirect costs, engineering and owner's costs, labor productivity, ancillary equipment and systems, revamp items, duct work, area paving, lighting, utilities, safety systems, control system connections and programming, instrumentation, sootblowers, etc.) As a point of reference, the TIC factor used by NEC, in this analysis, is 90% of the average TIC factor of 4.9 used to estimate SOx control costs in NEC's SOx RECLAIM report.

NEC Estimated FCCU Feed Rates from
Flue Gas Rate Data Provided by SCAQMD
Correction of NEC PWVs Required

SCAQMD staff is correct in pointing out that NEC used incorrect design capacities in developing the FCCU SCR costs shown in section 1.2 of NEC's non-confidential report (14-045-4, November 26, 2014). NEC back calculated expected FCCU rates from flue gas flow rate data provided by AQMD staff to obtain estimated FCCU sizes. The following table presents a revision to the report table based on corrected FCCU sizes as indicated by district staff. Also included in the table is an update to the cost of a Grass Roots SCR for Refinery 6 based on a comparison of flue gas rates to the SCR versus the typical (base case) SCR. Revised NEC estimates provided in Table 2 do not include any reduction to NEC's original cost estimate model.

Table 2 (Restatement of Table F.2)
Estimates of PWV Correcting NEC Values for FCCU Feed Rates

Facility	FCCU Feed, kBPD	AQMD's Estimate, $M	Revised NEC Estimate, $M	Ratio: NEC/AQMD
5	71	33	43(2)	1.3
6	90	57	62(1)(2)	1.09
7	55	27	37	1.37
4	34/36(3)	16	28	1.75
9	55	19	37	1.95
Total		152	207	1.36

Notes:

1. The PWV shown includes the impact of additional flue gas from a CO boiler but does not include the incremental flue gas from another source which is fed to the existing SCR.
2. Costs shown are for grass roots (new) SCR additions to existing FCCUs. Existing units may be modified to reduce compliance costs below those indicated.
3. Staff report throughput is 34 kBPD. Published unit capacity is 36 kBPD.

**Staff Evaluation of NEC PWVs vs. Refinery 1 SCR Costs
Does Not Factor In Project Scope Differences**

Staff provided a review of NEC's cost estimates based on a comparison to the cost provided for Refinery 1's SCR to demonstrate that NEC's estimating method is overly conservative. In this comparison staff claims that NEC's cost tool over predicts the cost of this installation by $11M (27%). The difficulty in comparing a specific project to a generalized curve is that the project has a specific scope which in most cases is different than the assumed scope of the "typical" project. This is the case for the SCR installation at Refinery 1 which, according to Refinery 1 personnel, did not include the cost for waste heat boiler modifications. Subtracting this component from the TIC for a typical FCCU SCR installation and recalculating PWV yields a cost of $45.45M which is 10.8% higher than staff's cost work-up on this project of $41M, not the 26% difference indicated in Appendix F. Staff had the WHB cost information NEC used in our estimates, we do not understand why they did not make the PWV comparison on the same basis.

**Staff Evaluation of NEC PWVs vs. Refinery 9 SCR Costs
Misstates Vendor and NEC Information**

Staff also provided a review of NEC's cost estimates based on staff's assessment of differences between the data provided by an SCR vendor to staff and NEC for an installation at Refinery 9. In staff's evaluation of the data provided by the vendor they incorrectly calculate the total catalyst volume to be 3,100 ft^3 vs the actual vendor proposal which provided only 2,400 ft^3. Staff also incorrectly calculates NEC's estimated catalyst volume at 12,697 ft^3 vs an actual value of 4,600 ft^3 (1.92 x vendor proposal, see previous discussion on catalyst volumes and specification of a third bed).

**Comments on Staff's Determination of
PWVs for FCCU SCRs**

I would like to take the opportunity to provide a few comments on SCAQMD staff's determination of PWVs for FCCU SCRs.

1. In using the costs provided for Refinery 1's SCR staff is assuming that all district SCRs can be installed without any impact on upstream equipment and that installation of the SCR can be executed in an open, non congested area. Refinery 1's SCR was installed prior to the installation of a large ESP, which occurred around 2006. If the SCR was to be installed today, or at any time after installation of the large ESP, costs would be higher due to productivity debits associated with working in a congested area and quite possibly even higher due to the need to move or modify some equipment to make the installation possible. In the most extreme case the SCR and ducting may have to be field erected from small fabricated assemblies due to access constraints.

2. Staff used a 0.7 power factor to scale the costs for Refinery 1's SCR project to different sizes. Costs for FCCU regenerator flue gas systems scale more accurately when a figure of around 0.6 is used. The effect of using a larger scale factor is a greater reduction in project costs for all projects with the differences getting proportionately greater the further one gets from the base case unit size. In essence using the 0.7 factor instead of 0.6, in this particular evaluation, will decrease costs for all units and will disproportionately decrease the cost of smaller units.

3. In using vendor budget quotes for SCRs, staff needs to add erection labor to the vendor quote. There is no indication that this is done in staff's analysis.

4. Staff does not condition the vendor's quotes to account for operational conditions, including unit upsets, and other project unknowns which will have direct bearing on SCR design details, performance and costs. An allowance must also be made for the accuracy inherent in vendor's budget quotations, which does not appear anywhere.

5. The PWVs provided for Refinery 7 and Refinery 9 are \$27M and \$19M respectively. There is an apparent inconsistency in these numbers as the stated capacity for each of these units is 55 kBPD. Units of the same capacity should have PWVs close to one another not differing by 42%. Staff should check these numbers and ensure that the SCR project scope differences between these two units can explain the large difference in cost.

In the interest in getting our comments into your hands as soon as possible we will provide comments on Staff's review of our SCR estimates for other applications in the district in one or more separate letters.

I am looking forward to discussing the items identified in this letter with SCAQMD staff and invite them to meet with us at our office in Montville, NJ.

Sincerely,

James P. Norton
President & CEO

cc:

<u>NEC – Montville, NJ</u>
P. M. Corritori
J. A. Norton
R. S Todd, PhD
D. Vizzuso
S. Zhang, PhD
Z. Zhang

<u>NEC – Swedesboro, NJ</u>
W. A. Lincoln
C. A. Steves

<u>NEC – New Orleans, LA</u>
S. G. Haydel

<u>AFPM – Washington, DC</u>
A. Adams – AFPM
C. Gleason – Chevron Phillips
M. Hodges - Valero
T. Kruzich - Chevron
S. Moyer – Holly Frontier
D. Pavlich – P66
D. Price - Tesoro
K. Saffell - Valero
B. Williams - AFPM

<u>Chevron El Segundo Refinery</u>
J. Doyle
S. Worley
R. Spackman

<u>ExxonMobil Torrence Refinery</u>
S. Holm
P. Sheng

<u>Paramount Refining Co.</u>
K. Gleason
H. Chang

<u>P66 LAR</u>
K. Beruldsen
S. Micucci

<u>Tesoro Carson / Wilmington</u>
S. Stark
F. Colcord
D. Kurt

<u>Valero LA Refinery</u>
N. Irwin
M. Smith

<u>WESPA</u>
S. Gornick

112 Main Road, 2nd Floor
Montville, NJ 07045
Office: 973-394-9330
Fax: 973-394-9336
www.nortonengr.com

James P. Norton
President & CEO
Office: 973-394-9330 x200
Mobile: 201-314-2038
jpnorton@nortonengr.com

September 4, 2015

Philip M. Fine, PhD
Deputy Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765-4178

Comments on Preliminary Draft Staff Report
Proposed Amendments to Regulation XX
Regional Clean Air Incentives Market (RECLAIM)
NOx RECLAIM – SCRs for Fired Heaters & Boilers
Document No. 14-045-8

Dear Mr. Fine,

We have completed a review of the above captioned report's discussion of SCR applications to district Refinery Fired Heaters and Boilers and have identified several misstatements and/or misunderstandings of the information provided by our company, under contract from SCAQMD, which may have material impact on the conclusions drawn by staff in the report. It is my intent in this letter to clarify the most glaring misstatements/misunderstandings of the information we provided to the district both in our final report (Doc. No. 14-045-4, Nov. 26, 2014) which summarized the data on a non-confidential basis, and the details provided on a confidential basis to the district and individually to each of the refineries.

We stated, quite clearly, in the final report and in subsequent discussions with staff, that we agree that 2 ppmvd (3% O_2) NOx emissions is a justifiable emission level for SCR applications to FCCUs, Fired Heaters, Boilers, Gas Turbines and TGU/SRUs, with caveats. While a few existing units can meet this guideline under current operating conditions, many more, similarly designed units have not demonstrated similar low emissions capabilities. With the exception of Gas Turbine installations (which have an equivalent emission level of 6 ppmv @ 3% O_2) most low emission SCRs in service today, being built today and even those being designed today carry manufacturer's guarantees to meet a NOx limit of 5 vppm @ 3% O_2. In spite of the limited number of units (other than gas turbines) operating at or below 2 vppm NOx, we believe that it is possible to achieve these levels, but to guarantee long term reliable performance (refineries typically operate 24/7 for periods of 4 to 6 years) it is prudent and quite possibly necessary to design future SCRs to increase residence time, improve

NH_3 distribution, improve overall flue gas flow distribution, add catalyst, etc. SCAQMD staff agrees with this concept but we have strong disagreement as to how much change from current SCR designs will be required to achieve the sought after NOx reductions not only on day one but at the end of year one and year five and beyond.

NEC's engineers have extensive experience in process development, equipment development and project development for the refining and petrochemical industry in the manufacturing and air pollution control areas. The experience level of the engineers who completed our technology and project cost evaluations is 51, 37 and 8 years. It is exactly this experience base, and past successful work with the district, that caused you to look to NEC to develop "cost guidance" for evaluating the refining sector. We find it very surprising therefore, that staff essentially ignored our recommendations and continued to use what we feel are unrealistically low costs for NOx control projects for district refineries.

Comments on Heater SCR Project Costs

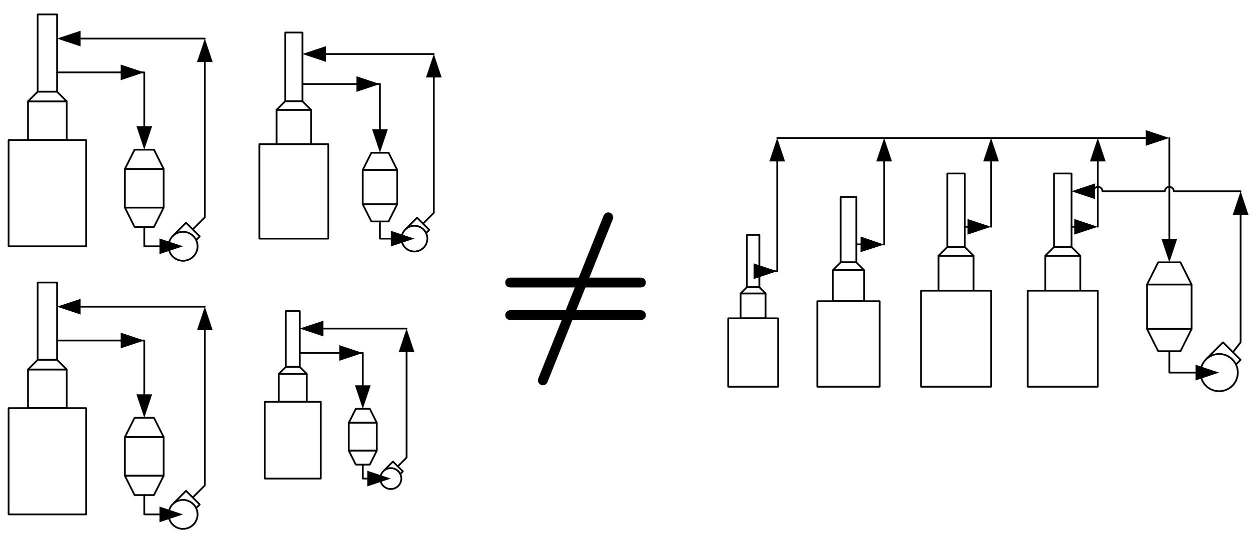
Appendix G to Staff's Draft Report presents a review of NEC's analysis of Heater and Boiler SCR costs by SCAQMD staff. It concludes that NEC's estimated costs for NOx control are excessive and gives the following reasons for this assessment:

- NEC recommendations did not include an assessment of the efficacy and cost of alternative NOx control technologies.
- NEC developed TIC estimates using a direct M&L multiplier of 4.5 vs staff's use of a TIC factor of 3.87.
- NEC used SCR catalyst and enclosure costs, obtained from SCR suppliers, for FCCU applications and used these costs as a basis for estimating the cost of heater and boiler SCRs.
- NEC recommends including space for four catalyst beds and designing for superficial gas velocities of 10 ft/sec.
- NEC included costs for new CEMS in their project cost estimates.
- NEC's costs estimates for smaller heaters and boilers are biased high by specification of ammonia systems which are too large for these small units.
- NEC's operating costs are biased high due to the cost of catalyst replacement which is higher if/when with higher installed catalyst volumes.
- NEC's estimates are skewed high because they are higher than staff's estimates which are conservative in the base case.
- NEC conditioned budgetary quotations from manufacturers for the accuracy of the quote, the accuracy of the project basis and for the application of refining industry standards for construction of the equipment.

- NEC includes the cost of installation of the SCR in its estimate to arrive at a direct material and labor cost for the SCR component of a project at 75% of the equipment cost. Characterized by staff as: "additional labor".

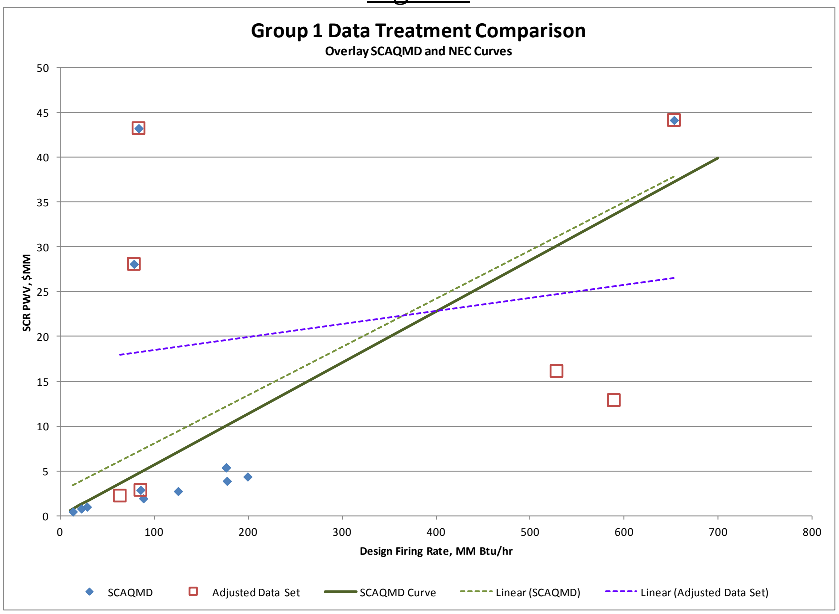
Before getting caught up in the minutia of Appendix G, I want to first present an overall picture of the PWV estimates developed by AQMD staff and those developed by NEC. The first thing we noticed in reviewing staff's use of refinery cost survey data, was that PWVs for SCR installations servicing multiple heaters were broken down and allocated to each heater based on design firing rate. This was done to obtain data points for SCR installation costs for individual heaters as a function of heater design firing rate. The problem with parsing the data in this manner is that it assumes that project costs for multiple heater installations and single heater installations are equivalent. They are not. Sharing an SCR between heaters is always lower cost than installing an SCR on each heater. We estimate that multiple heater SCR installations can cost as much as 30 to 70% of single heater installations with the savings coming from a reduction in SCR box steel and structural support, a reduction in the number of fans required for the installation, a reduction in foundations, ammonia distribution piping, controls, etc.

I believe that the following sketch provides a much better explanation of the difference between multiple and single heater SCR installations:



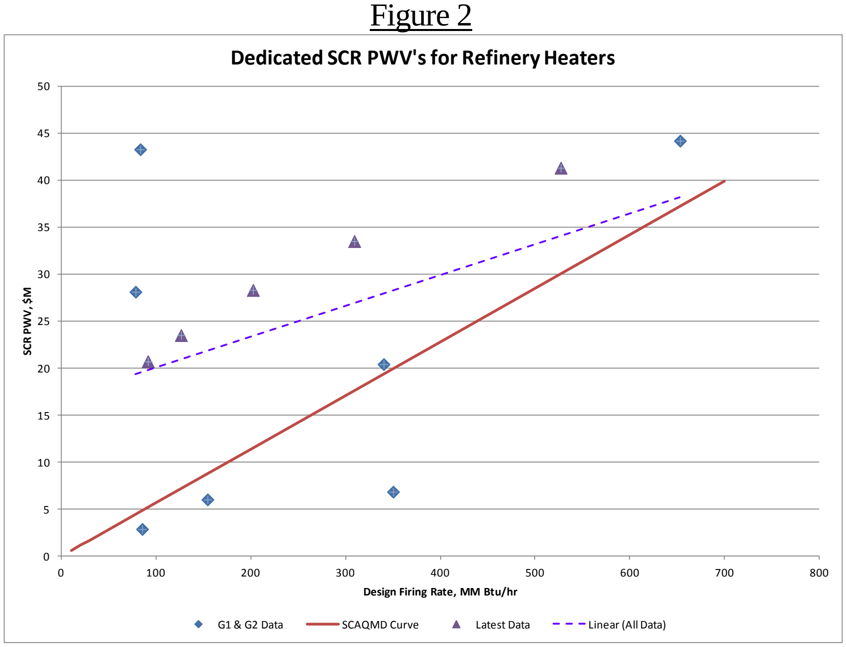
The following figures provide an illustration of the effect of staff's cost allocation assumption on the estimated PWVs of small heaters. Figure 1 presents two sets of survey cost data denoted as Group 1 data in the draft report. The data set named SCAQMD includes the parsed PWV data for three of the seven best performing SCRs in the district resulting in a total of fourteen data points. The data set named "Adjusted Data Set" combines the duties of the seven heaters which share SCRs into three data points yielding a total of seven data points. The revised data points represent SCR systems designed for a heater with a size equal to the combined firing rate of all the heaters sharing the SCR. Linear regressions of the parsed and non-parsed data are shown as dashed lines in the figure. The solid line is staff's PWV relationship. While the data is widely scattered and does not curve fit very well (R^2 = 0.3 for curve fit of parsed data and 0.05 for non-parsed data) the slopes of the two curves are very different and indicate that staff's correlation likely under predicts PWVs for heaters smaller than 400 MM Btu/hr; quite a different conclusion than that drawn in the draft report.

Figure 1



Norton Engineering understands that the number of survey project and operating cost data points on high performing SCR units is both limited and scattered and that additional information is needed and has been used by staff to generate more representative PWVs for refinery heaters. Figure 2 provides a comparison of staff's PWV correlation with available Group 1, Group 2 and additional SCR project cost estimate data provided to AQMD by a district refinery during NEC's review. All data are for dedicated SCR installations.

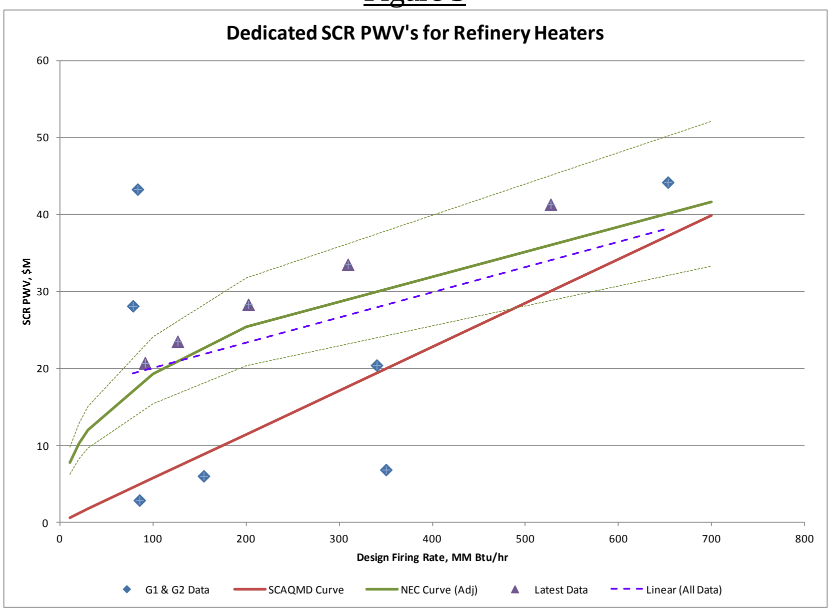
Figure 2



The purple dashed line in the figure represents a linear regression line for all the chart data. As with Figure 1, the large scatter in the data makes the correlation, any correlation, almost meaningless. The conclusion we can reliably draw from this chart is that staff's PWV correlation under predicted PWVs (based on actual and estimated TICs) in eight out of twelve instances, over predicted PWVs in one out of twelve instances and was accurate in three out of twelve instances. If staff's correlation was conservative we would expect that it would over predict PWVs more often than it under predicted PWVs. That is clearly not the case.

Figure 3 is a repeat of Figure 2 including NEC's proposed PWV correlation and the cost bands recommended for use in estimating complex and simple, single heater – single SCR PWVs.

Figure 3



NEC's proposed correlation provides PWV estimates for dedicated SCR projects which are more representative that staff's proposed correlation, matches up pretty well with the linear correlation of all data and, is not overly conservative. Six data points are higher cost than predicted by NEC's correlation, four are lower cost and two are predicted pretty accurately. When the complexity bands are used, the correlation under predicts in two of 12 cases, over predicts in four of twelve cases and is "accurate" in six of twelve cases.

For the specific case of smaller heaters (<100 MMBtu/hr heat release) NEC's correlation shows a very steep slope indicating that costs for small heater SCR installations rapidly increase with increasing heater size. This size sensitivity is expected as fixed project costs and non-size dependent project costs are normally a higher percentage of small projects than they are of larger projects. Staff's proposed correlation does not show this trend and therefore can be expected to significantly under predict PWVs for smaller heaters.

The following paragraphs address each of staff's comments and objections and provide additional information and clarifications to address what we perceive as staff's misunderstanding of the information presented in our final report. While the items covered in the following paragraphs may be open to interpretation, our previous analysis of available cost data indicates that any changes SCAQMD staff might want to make to NEC's "typical fired heater and boiler project basis" will likely necessitate changes to equipment definition, equipment cost or estimate cost factors to improve the cost correlation with Group 1, Group 2 and subsequent project cost data.

Scope of NEC's Review of AQMD Staff's Preliminary Draft Report – September 23, 2014

This comment seems irrelevant to the current discussion as Staff's entire discussion on refinery heaters and boilers is focused on SCR installations as BARCT for the 2 vppm emission limit. We discussed this with staff during our work and staff agreed that any dilution of our effort to evaluate these alternative technologies would not be desirable.

Using FCC SCR Costs Increased Heater & Boiler SCR Cost Estiamtes

Staff provided NEC with heater and boiler SCR cost data from vendors for review. In our discussions with SCR vendors we focused on the more severe FCC applications and obtained detailed information on SCR costs for these applications. Much less data was available from staff's contact with SCR vendors. Attempts were made to obtain clarifications from SCR vendors which were either not received or received after issuance of NEC's report. In reviewing the design and operation of the best heater in the district (1.6 vppm outlet NOx) we found that inlet gas velocities were similar to our recommendations for FCCU SCRs while catalyst volumes were significantly less. Using the FCCU SCR cost as a basis NEC estimated and added the cost of and ID fan, an ammonia storage tank, and a new CEMS for each SCR project. We then factored the cost as described previously to arrive at a total project cost. We then compared the result of this method to available data on past and planned projects, Group 1, Group 2 and recent refinery estimates, and found the accuracy of this method to be reasonable and more accurate than staff's PWV correlation. Considering the scatter in the data and the relative good accuracy of the methodology we did not go further in refining any underlying assumptions or our cost estimating technique.

NEC TIC Factor of 4.5 vs. Staff TIC Factor of 3.87

Details of how NEC developed the factored estimates we used to generate TICs and ultimately PWVs for heater and boiler SCR installations have been described at length in our SOx RECLAIM cost review report (Non-Confidential Report No. SCAQMD 10-014-04 dated June 10, 2010). All of the factors used in this analysis are consistent with those used for our SOx RECLAIM assessment. Additional discussion is also available in our letter of August 10, 2015 commenting on AQMD staff's assessment of NEC's FCC SCR PWVs.

It appears that staff relied on SCR vendor cost data (Group 3 data) to generate SCR project costs for heaters and boilers without adjusting vendor costs for the budgetary nature of the estimates, the screening level of the process data provided to the vendor, the cost of equipment installation or the need for ancillary equipment such as ducting, fans and controls. All of these components are typically included in a cost estimate before the addition of TIC factors which cover, undefined equipment and systems, indirect project costs, engineering, project management, operator training, start-up spares, civil works and site preparation, project contingency, shipping and taxes. Staff's use of a TIC factor of 4.0 applied to the budget cost of the SCR provided by a vendor is not adequate to cover the cost of the entire SCR project.

Basis for SCR Catalyst Increase and Velocity Reductions vs Vendor Budget Quotes

The district has 7 SCRs installed on 14 fired heaters, achieving 1.6 to 3.5 ppmv NOx @ 3% O_2. The best performing unit treats flue gas from four heaters with a combined total design firing rate of 589 MM Btu/hr and is designed to treat flue gas to achieve 5 vppm NOx at this rate. Reported operation of this unit is 65% of design when achieving <2 vppm NOx emissions. Low firing rate operation decreases superficial and space velocities across/through the SCR versus design conditions (lower flue gas mass flows and lower flue gas temperatures vs design) lower velocities and space velocities translate into improved unit performance. In addition, lowering heater firing rates cools the heater firebox which also decreases inlet NOx levels to the SCR.

More important to the current discussion on SCR application to achieve 2 vppm emissions limits is the use of design data for this unit by staff, to extrapolate catalyst volumes and system costs for design of new units. Since the "base" unit is operated at 65% of design, any use of this data in an extrapolation to other applications needs to account for the lower than design operating conditions. It is not apparent from our review of staff's assessments if they have made this adjustment which will be a minimum 54% increase in the costs of the base unit.

NEC looked at the available operating data and the SCR manufacturer's information provided by staff for our assessment. We interviewed the SCR owners and made the assessment, based on information obtained during these interviews and our experience in developing oil processing, infrastructure and environmental control projects for over 20 years in the US and International refining industry, that estimating typical SCR sizes, based on the design conditions for the best SCR in the district, which isn't operating anywhere near its design condition would result in specifying/costing units which were too small. The question of catalyst volume then became one of how much additional catalyst might be needed to ensure long term reliable operation of an SCR. For refiners this translates into an SCR design which does not limit refinery or unit operation at any time between scheduled turnarounds.

Final determination of SCR catalyst volume for a typical refinery heater application requires making a flue gas throughput correction to the base case design, as note above, and making adjustment to catalyst volumes quoted by vendors where catalyst change out times are shorter than five to six years. To achieve the long run lengths required in refinery applications, refiners will increase catalyst volumes to offset declining catalyst performance. This is done in the design of every fixed catalyst bed system in the refinery. Based on the vendor information provided by AQMD staff a doubling of vendor catalyst volumes would be needed to ensure reliable operation in excess of five years. The minimum adjustment to achieve 2 vppm NOx and long unit operating life is therefore 3x (1/0.65 * 2) typical vendor specified or currently installed catalyst volumes.

NEC included a total of four catalyst beds for 2vppm NOx designs when three beds will likely prove adequate. Our inclusion of the fourth bed was to provide operating flexibility to ensure long term compliance while burning variable composition refinery fuel gas. This bed added 11 ft to the height of a typical SCR compared with a three bed unit. Elimination of this bed will reduce proposed SCR height by less than 20% and will not have any impact on the cross sectional area of the catalyst bed. Adjusting the SCR cost to reflect this change will necessitate a change in TIC estimating methodology to improve the correlation with Group 1, Group 2 and subsequent project cost data (Figure 3).

Cost of New CEMS vs Upgrade

NEC did not have any data on the status/condition of existing CEMS and therefore included the cost of a new CEMS, CEMS enclosure, stack platforms, access, etc. in the heater and boiler SCR project TIC estimates. A reduction in this cost will necessitate a change in estimating methodology to improve the correlation with Group 1, Group 2 and subsequent project cost data (Figure 3).

Specification of "Large" Ammonia Storage Tanks Biases Costs for Small Heaters High

A stand alone ammonia storage system will include a storage tank with sufficient volume to receive a full truck load of ammonia while operating with a heel sufficient to run the associated SCR for a defined, short, period of time. Local bulk ammonia suppliers suggest a minimum tank size of 11,000 gallons. NEC used this tank size as the basis for all district SCRs without increasing size for larger heaters which will receive ammonia deliveries more frequently.

NEC did not include the likely cost savings impact of centralized ammonia storage and distribution systems in our analysis. While on the surface it appears that significant savings can be gained from such systems, the need for long runs of small bore piping on existing pipe racks, through operating units, with frequent pipe supports (small bore piping cannot span typical pipe rack supports and needs multiple intermediate supports) and requiring significant scaffolding to be erected, makes ammonia distribution from centralized storage facilities nearly as costly as dedicated storage, and in some cases more expensive. For this reason, dedicated storage is a more reasonable option during early stages of project definition.

High Catalyst Replacement Costs Skewed NEC PWVs High

Staff is correct in their assessment that high catalyst volumes (FCCU SCR basis) in NEC's basis yielded high catalyst replacement costs and increased PWVs for heaters and boilers. A correction to annual operating costs should be made to correct this error. When this is done PWVs estimated by NEC's correlation will drop and will under predict Group 1, Group 2 and subsequent project cost data. An adjustment in NEC's TIC estimating method will be required to reestablish prediction accuracy for PWV (Figure 3).

NEC's Estimates are Higher Than Staff's "Conservative" PWVs

Staff has incorrectly used NEC's PWV correlation to demonstrate a reported 250+% difference in cost for a refinery SCR. Table G. 8 is recreated below with an additional column showing the correct use of NEC's correlation for PWV.

Table G. 8A – SCR Costs Estimated by Staff and NEC for Four Process Heaters Vented to a Common Stack (Shared SCR)

Heater	Rating MM Btu/hr	Staff's Approach Upperbound PWV	NEC's Approach PWV	Corrected NEC Approach PWV
D471	177	$11 M	$27 M	--
D472	125	$11 M	$23 M	--
D473	88	$5.5 M	$20 M	--
D3031	199	$11M	$28 M	--
Total	589	$38.5 M	$99 M	$43.2 M

As discussed previously in this letter we expect the SCR project cost for shared units to be less than what would be calculated for each individual unit. Costs should be more in line with the cost of an SCR for the total fired duty of the heaters feeding the SCR. In this case the difference between staff and NEC is 12% not 250+%.

Based on the data which staff purports to use to "calibrate" their conservative PWV correlation for fired heaters and boilers, staffs correlation is neither calibrated nor conservative. NEC has provided AQMD with a reasonable correlation for estimating the cost of SCR installations on refinery heaters and boilers as validated by the same data set staff is using. We agree that operating costs for heater and boiler SCRs should be reduced in the PWV calculation to correct the operating cost impact of over specification of catalyst volume. After making this correction (staff has the TIC correlation) we recommend staff use the resulting PWV correlation to estimate the cost of heater and boiler NOx control.

It is a shame that NEC and AQMD find themselves disagreeing on so many items in a public forum. I wish that we had discussions on more of the specifics of our review of AQMD's draft report and our recommendations for changes to the way cost estimates were prepared between November 2014 and July 2015. Perhaps we could have clarified and/or resolved some of these issues prior to AQMD staff developing the draft report and the recommendations which are based on the cost evaluations in question. It would have certainly made everyone's life a little easier.

I am looking forward to discussing the items identified in this letter with SCAQMD staff and invite them to meet with us at our office in Montville, NJ.

Sincerely,

James P. Norton
President & CEO

cc:

NEC – Montville, NJ
P. M. Corritori
J. A. Norton
R. S Todd, PhD
D. Vizzuso
S. Zhang, PhD
Z. Zhang

NEC – Swedesboro, NJ
W. A. Lincoln
C. A. Steves

NEC – New Orleans, LA
S. G. Haydel

AFPM – Washington, DC
A. Adams – AFPM
C. Gleason – Chevron Phillips
M. Hodges - Valero
T. Kruzich - Chevron
S. Moyer – Holly Frontier
D. Pavlich – P66
D. Price - Tesoro
K. Saffell - Valero
B. Williams - AFPM

Chevron El Segundo Refinery
J. Doyle
S. Worley
R. Spackman

ExxonMobil Torrence Refinery
S. Holm
P. Sheng

Paramount Refining Co.
K. Gleason
H. Chang

P66 LAR
K. Beruldsen
S. Micucci

Tesoro Carson / Wilmington
S. Stark
F. Colcord
D. Kurt

Valero LA Refinery
N. Irwin
M. Smith

WESPA
S. Gornick

VIA ELECTRONIC MAIL

August 21, 2015

Dr. Philip Fine
Deputy Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

SUBJECT: NOx RECLAIM INDUSTRY COALITION COMMENTS ON CURRENT DISTRICT STAFF PROPOSED AMENDMENTS TO REGULATION XX DATED JULY 21, 2015

Dear Dr. Fine:

The following trade associations in representing their members have joined together to form the NOx RECLAIM Industry Coalition ("the Coalition"):

California Asphalt Pavement Association (CalAPA)
California Construction & Industrial Materials Association (CalCIMA)
California Council for Environmental and Economic Balance (CCEEB)
California Manufacturers and Technology Association (CMTA)
California Metals Coalition (CMC)
California Small Business Alliance (CSBA)
Regulatory Flexibility Group (RFG)
Southern California Air Quality Alliance (SCAQA)

Western States Petroleum Association (WSPA)
Los Angeles Business Federation (BizFed)

Members of the Coalition have been actively following the District staff proposals regarding a NOx RECLAIM shave ostensibly being proposed to reflect advances in Best Available Retrofit Control Technology ("BARCT") between 2005 (the last NOx RECLAIM shave) and today. Following the release of the preliminary draft staff report and the proposed amendments to Regulation XX on July 22, 2015, the Coalition members believed it necessary to make these written comments and ensure that staff is fully aware of our concerns and that those concerns are included in the administrative record.

PROPOSED SHAVE AMOUNTS AND TIMING

District staff has proposed the following shave implementation schedule:

Year	Shave amount (tons/day)
2016	4
2017	0
2018	2
2019	2
2020	2
2021	2
2022	2

A shave of 4 tons per day in 2016 does not allow any time whatsoever for facilities to develop and implement emission reduction measures. Indeed, it could potentially put many of the RECLAIM facilities at risk of non-compliance with their respective RECLAIM caps, resulting in deductions from their 2017 RTC allocations. Moreover, the District expects that the bulk of the BARCT emission reductions will be made at the refineries[1]. At NOx RECLAIM Working Group meetings, staff has conceded that those reductions will not be achievable for several years into the future, at the earliest, due to the complexity of the permitting and siting issues and the magnitude of the construction activities necessary to achieve the BARCT levels projected by District staff. Thus, it is illogical to require the largest shave amount to occur at the earliest possible date.

The Coalition understands that the District has committed itself in the currently operative AQMP to implement a certain level of NOx reductions from the RECLAIM universe as a contingency measure if the District failed to attain the 24 hour PM2.5 NAAQS by the end of 2014. However, there is no commitment in the AQMP to make a 4-ton per day shave in 2016. Indeed, the AQMP contemplated a 2-3 ton per day reduction in Phase I and another 1-2 tons per day in Phase II. (Preliminary Draft Staff Report, page 2). Moreover, the AQMP specifically considered <u>and rejected</u> whether such an early action shave should remove all "excess" RTCs (i.e., the entire

[1] SCAQMD PDSR, Proposed Amendments to NOx RECLAIM, July 21, 2015, page 18.

"gap"). Rather, it was determined that only a 2-ton per day reduction was appropriate. Accordingly, the Coalition believes that the shave amount for the period 2016-2017 should be no more than 2 tons per day, and that there is no reason that all two tons have to be shaved in 2016. In fact, given that 2016 is almost upon us, and certainly will be by the time the amendments are adopted, it may be appropriate not to make any adjustments to 2016 allocations. Finally, we believe that the public record supports the view that the Governing Board approved the AQMP and CMB-01 with the understanding that if the 24 hour PM2.5 NAAQS was not attained, no more than 2 tons per day would be removed and that additional NOx reductions from RECLAIM would not be needed as a contingency measure to meet this purpose.

With respect to the total amount of the shave, the Coalition continues to believe that shaving a total of 14 tons per day of RTCs from the RECLAIM market in order to achieve the 8.79 tons per day reductions the District seeks to obtain as a BARCT adjustment is neither necessary nor justified.[2] We understand that District staff believes that the BARCT reductions won't occur unless almost the entire "gap" between RTC holdings and reported NOx emissions has been eliminated. History has shown that the staff is incorrect on this assessment. As shaves have been implemented, emissions have gone down to reflect past BARCT adjustments, even as the "gap" has remained relatively stable at 5-9 tons per day. A shave of 14 tons per day is excessive and risks destroying the RECLAIM market.

Finally, when implementing the shave, the amounts in the early years should be smaller and larger increments should be reserved for later years, to allow the BARCT installations to be implemented.

COST EFFECTIVENESS

The Coalition continues to believe that a 25 year useful life assumption (used consistently for all equipment in this proposed rulemaking) is not appropriate for all equipment. Additionally, we believe that the District staff has underestimated the cost for several equipment categories. District staff minimizes control costs by using a cost-effectiveness calculation[3] that is not used by the California Air Resources Board and most other major California air districts. Additionally, the use of a $50,000 per ton figure as the cost threshold is more than twice the $22,500 per ton threshold applied to command-and-control regulated sources. This is inconsistent with Health and Safety Code Section 39616 which requires that the RECLAIM program "not result in disproportionate impacts, measured on an aggregate basis, on those stationary sources included in the program compared to other permitted stationary sources in the district's plan for attainment."

We also note that Norton Engineering (the third party independent contractor retained by the District to review and assess the District staff's cost effectiveness determinations) has raised

[2] The Coalition does not believe that the 8.79 tons per day figure is necessarily the correct number. We continue to take issue with the SCAQMD staff's cost-effectiveness calculations for a number of source categories and understand that Norton Engineering, the SCAQMD's third party BARCT evaluator, continues to have issues with the staff analysis as well. This will be discussed separately in this letter.

[3] The use by SCAQMD of the discounted cash flow (DCF) method as well as generous assumptions regarding useful life and interest rates result in cost effectiveness figures that show lower costs per ton of emissions reduced than other, more accepted, calculation methods.

questions regarding the District staff's cost effectiveness determinations and its dismissal of Norton Engineering's analyses when those analyses showed higher costs than the District staff's evaluation showed[4].

NEED FOR THE "GAP"

Our analysis has shown that even if the District staff concluded that NO BARCT improvements had been made between 2005 and today, the staff's methodology would result in 6 tons per day of NOx RTCs being removed from the program. RTCs being removed under the District's methodology would include those needed for:

- NSR Holding Requirements
- Electric Grid Reliability and Implementation of AQMP Attainment Strategies (i.e., large scale electrification to replace current combustion processes)
- Post-2023 Growth
- Investor Holdings
- Shutdowns
- ERC Conversions

Additionally, there are significant questions regarding whether the District staff's proposed 10% compliance margin is sufficient. A 10% compliance margin will likely be insufficient to assure sufficient liquidity to maintain a functioning market in light of the removal of the above listed RTCs from the program.

We are also concerned that RTCs reflecting investor holdings and ERC conversions are proposed to be "taken" by the District as a result of the District's BARCT shave methodology with no analysis of the financial impact or the costs associated with such a taking[5].

We understand that District staff is working with electric power generators to address the NSR holding requirement issue[6]. While the Coalition agrees that something must be done to address the NSR holding requirement, the current proposal is a complicated attempt to address a problem that only arises because the District staff is trying to eliminate the "gap" altogether. One of the complicating factors associated with the current staff proposal is that it would allow the Adjustment Account to be utilized both to address the NSR holding requirement and to cover actual emissions from power plants under certain contingencies. This brings into question whether or not the Adjustment Account will be adequately funded to cover potential demand. Furthermore, the proposal is fraught with risk because it needs EPA approval, which is not assured. The Coalition believes that the size of the shave should not include RTCs that are required to be held for NSR holding purposes. However, if the District insists on going forward with its proposal, no amounts of RTCs held by electric power generators to satisfy their NSR holding requirements should be shaved unless and until EPA approval is finalized.

[4] NEC-SCAQMD letter dated August 10, 2015.
[5] SCAQMD PDSR, Proposed Amendments to NOx RECLAIM, July 21, 2015, Chapter 4.
[6] SCAQMD Staff stated meetings were being held with power-related stakeholders at the June 4 and July 9, 2015 working group meetings.

In summary, the District's proposed shave goes way beyond what is required to comply with the Health and Safety Code requirements with respect to a BARCT adjustment and runs the risk of repeating the program "meltdown" of 2000-2001 during the power crisis when insufficient RTCs were available.

ENERGY EFFICIENCY PROJECTS

As we stated in our June 19, 2015 comment letter, the Coalition strongly opposes any effort to further reduce RTC allocations due to "energy efficiency projects" that have or would reduce NOx emissions. Any reduction in NOx emissions not strictly required by BARCT should be encouraged and the benefits of making those reductions retained by the facility operator making them. For the District to consider taking away RTCs due to reductions in emissions occurring from efforts to improve energy efficiency would be a true manifestation of "no good deed goes unpunished."

CONCLUSION

We look forward to continuing to work with the District staff to develop a RECLAIM shave that represents a true BARCT adjustment while not endangering the life of the RECLAIM program. RECLAIM has been extremely successful in reducing NOx emissions from stationary sources while providing them the flexibility to make reductions in the most cost effective manner. We are very concerned that the severe reductions in RTCs currently being proposed by District staff go beyond adjusting for new BARCT and will result in facilities being subjected to the same RTC shortages that plagued the program in 2000-2001.

Respectfully,

Curtis L Coleman

Curtis L. Coleman
Executive Director, Southern California Air Quality Alliance
On behalf of the NOx RECLAIM Industry Coalition

cc: Dr. Barry Wallerstein, SCAQMD
SCAQMD Governing Board Members

650 Town Center Drive, 20th Floor
Costa Mesa, California 92626-1925
Tel: +1.714.540.1235 Fax: +1.714.755.8290
www.lw.com

LATHAM&WATKINS LLP

FIRM / AFFILIATE OFFICES
Abu Dhabi
Barcelona
Beijing
Boston
Brussels
Century City
Chicago
Dubai
Düsseldorf
Frankfurt
Hamburg
Hong Kong
Houston
London
Los Angeles
Madrid
Milan
Moscow
Munich
New Jersey
New York
Orange County
Paris
Riyadh
Rome
San Diego
San Francisco
Shanghai
Silicon Valley
Singapore
Tokyo
Washington, D.C.

August 20, 2015

Mr. Joe Cassmassi
Planning & Rules Director
Planning, Rule Development & Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Comments on Proposed Amendments to Regulation XX, NOx RECLAIM

Dear Mr. Cassmassi:

We are writing on behalf of Southwest Generation Operating Company, LLC ("SWG") and its subsidiary Harbor Cogeneration Company, LLC ("HCC"), which owns a power plant located at the Port of Long Beach at 505 Pier B Street, Wilmington, California (Harbor Cogeneration Plant). The plant is listed as one of the top 90 percent of RTC holders that would be subject to a 47% "shave" in NOx RECLAIM Trading Credit ("RTC") holdings under the proposed amendments to South Coast Air Quality Management District (the "District") Regulation XX released by staff on July 20-22, 2015.

Basis for HCC Comments

The stated purpose of the proposed amendments to Regulation XX is to reduce NOx emissions from the universe of RECLAIM facilities by 2022 in line with current best available retrofit control technology (BARCT). The District staff has decided that the best way to achieve this goal is by reducing the holdings of the largest RECLAIM NOx holders in the basin. This includes the Harbor Cogeneration Plant and over 50 other power plants, refiners, industrial facilities and investors.

As HCC has discussed with District staff, its primary concern and the basis for submitting this comment letter is the District's proposal that the baseline date from which the "shave" will be taken be retroactive to RTC holdings as of March 20, 2015. The first time HCC was made aware that staff was proposing the March 20, 2015 baseline date was just prior to the public workshop on July 22, 2015. We understand the desire to establish a baseline to prevent manipulation through multi-step disposition and re-acquisition strategies. However, the current staff proposal to establish a retroactive baseline date without prior advance notice constitutes an unprecedented *ex post facto* action that unfairly disadvantages entities that have made good faith trades subsequent to the proposed baseline date.

Relevant Rule Language

In its rollout of the proposed amendments to Regulation XX, the District issued proposed revisions to Rules 2002 and 2005 on July 20, 2015, followed by proposed revisions to Rules 2011 and 2012 on July 21, 2015. The primary amendments are in Proposed Amended Rule (PAR) 2002. In paragraph (f), Annual Allocations for NOx and SOx and Adjustments to RTC Holdings, the proposed amendments to subparagraph (f)(1)(C) would apply to the Harbor Cogeneration Plant. The relevant proposed amended text of subparagraph (f)(1)(C) states:

> (C) The Executive Officer will adjust NOx RTC holdings, as of (Date of Amendment) for compliance years 2016 and thereafter by multiplying the amount of RTC holdings as of *March 20, 2015* by the following adjustment factors for the relevant compliance year to each of the Facility Permit Holder listed in Table 8 to obtain tradable/usable and non-tradable/non-usable holdings: . . . (emphasis added)

We understand the need to set a baseline date in order to establish the inventory and identify potentially affected sources. However, choosing a retroactive baseline date without prior advance notice of the proposed date would be an *ex post facto* action that unfairly disadvantages entities, like HCC, that made good faith economic decisions in reliance on the rules in place at the time.

An *ex post facto* law or regulation is one that retroactively changes the legal consequences or status of actions that were committed, or relationships that existed, before the enactment of the law or regulation. Article I, Sec. 9 of the California Constitution prohibits the passage of *ex post facto* laws. Furthermore, in In re Lomax, 66 Cal. App. 4th 639, 643 (1st Dist. 1998) (citing *People v. Armitage*, 194 Cal. App. 3d 405, 414 (1987); *Flemming v. Oregon Bd. of Parole*, 998 F.2d 721, 726 (9th Cir. 1993), the court held that "Regulations have the force and effect of law and thus are subject to ex post facto prohibitions" of the state constitution. It is therefore unambiguous that the Constitutional prohibition on *ex post facto* laws applies to agency regulations, such as those of the District. The current proposal runs afoul of that prohibition by retroactively changing the legal consequences and status of trades that were made in good faith and without advance notice of the proposed March 20, 2015 baseline date.

Impact on Facility Planning and Engineering

The District's proposed retroactive baseline date of March 20, 2015 frustrates plans that HCC, and perhaps others, have developed and begun to implement to achieve early emission reductions, thereby undermining the purpose of the RECLAIM program and the proposed amendments. HCC's planning window for engineering upgrades and plant performance improvements is a multi-year exercise. In order to accomplish their business goals, they implemented trades of their NOx RTC holdings this year that were completed after March 20,

2015. These trades were made to fund planned plant upgrades, including emission reduction strategies and possible plant expansions. This strategy is completely consistent with the market concept of the RECLAIM program. If the District were to retroactively reduce HCC's NOx RTC holdings, it would also retroactively alter the premises upon which they based their decisions to improve the plant during 2016 to 2020 such that those decisions may not make financial sense.

We are aware that other facilities in the basin have sold RECLAIM NOx perpetuity streams after the March 20, 2015 date. Presumably, the sales were used to finance upgrades to their facilities which would reduce emissions in the future (the fundamental purpose of this rule). The way PAR 2002 currently stands, like HCC, these entities would be penalized for their early actions to become more efficient and less polluting. The examples provided below illustrate some of the adverse consequences associated with the District's proposed action.

Example 1: A non-refining facility that held 100,000 pounds of NOx perpetuity RTCs on March 19, 2015 would be subject to a 47% shave. If this entity sold 50,000 pounds of NOx RTCs on March 25, 2015 to finance an upcoming project to reduce emissions, it would still be shaved 47,000 pounds based on its holdings of 100,000 pounds as of March 20, 2015. This would leave that facility with an allocation of only 3,000 pounds in 2022, far less than the facility originally planned. In this example the facility expected to reduce its emissions by half, finance a project with the proceeds from the sale of their future excess credits, and retain an allocation of emissions for future use. This example describes an action that should be applauded, rather than penalized, by the District because the facility is cutting its emissions.

Example 2: A facility may have sold all of its RTC holdings after the proposed baseline date, but before the shave date. For example, a facility may have held 100,000 pounds of NOx perpetuity RTCs on March 19, 2015 and sold all RTCs on March 25, 2015. The entity would be shaved 47,000 pounds of RTCs, but it has no remaining RTCs in its account. How would the District implement the shave? Would the District follow the RTCs and apply the shave to the purchaser, or would the facility "owe" 47,000 pounds of RTCs?

These are just a couple of examples of the potential consequences of the District's proposed action. We would expect the trading, selling and buying examples to be as numerous as the varied operations of the affected sources.

Baseline Date for RTC Holdings Should Be Date of Amendment

We urge the District to work with the affected sources to establish a baseline date that is not earlier than the date of adoption of the rule amendments. This would provide clarity to businesses making financial and operational decisions, and stability to the District in establishing a credible inventory. In no case should the effective date to determine baseline RTC holdings be earlier than the effective date of amendment.

We appreciate the opportunity to submit these comments and look forward to working with the District to refine and implement the proposed amended rules. If you have any questions please contact me or Bob Louallen, HCC's Senior Environmental Compliance Engineer at (702) 239-3712.

Kind regards,

Michael Carroll
of Latham & Watkins LLP

cc: Bob Louallen

Yorke ENGINEERING, LLC
www.YorkeEngr.com

August 21, 2015

Kevin Orellana, AQ Specialist
Minh Pham, AQ Specialist
SCAQMD
21865 Copley Dr.
Diamond Bar, CA 91765
Work: (909) 396-2000
E-mails: korellana@aqmd.gov
mpham@aqmd.gov

Subject: Comments on Proposed NOx RECLAIM Amendments

Dear Mr. Orellana and Ms. Pham:

Please find herein comments on the draft RECLAIM Rule language dated July 22, 2015.

NEW EMISSION FACTORS FOR RULE 219 EXEMPT EQUIPMENT

We support the District's August 19th proposal for new provisions in Rule 2012 Chapter 4 to allow equipment certified by either U.S. EPA, CARB, or SCAQMD to use an emission factor other than the default factor of 130 lb/mmscf to report NOx emissions.

Currently, when a RECLAIM facility installs an SCAQMD Rule 1146.2 certified hot water heater, they are directed by District staff to report their RECLAIM and Annual Emissions Report (AER) emissions using a default emission factor of 130 lbs NOx/MMscf natural gas (equivalent to ~102 ppm of NOx), even though the unit has been certified by the SCAQMD to be "less than or equal to 20 ppm of NOx emissions (at 3% O2, dry)…" per Rule 1146.2. The estimated emissions factor associated with 20 ppm is approximately 25 lbs/MMscf, which is less than the 2010 ending emission factor. Manufacturers may not sell heaters for use in the District unless it complies with Rule 1146.2. We support that the RECLAIM rules are proposed to be modified to allow accurate reporting of emissions for R219 exempt equipment.

RULE 219 EXEMPT EQUIPMENT REPORTING

The District's August 19th proposal for certified Rule 219 exempt equipment indicates source tests may be required to verify lower emissions. We request that no source test shall be required for certified equipment. The SCAQMD specifies the emission certification process and accepts the documentation provided by the manufacturer as adequate to demonstrate compliance with the emission standards of Rule 1146.2. Certified heaters/boilers have been available on the market for years, tested by the manufacturers, low NOx combustion technology is achieving well under 30 - 55 ppmv, and the heat input ratings of Rule 219 equipment are small. Moreover, facilities may have multiple small boilers onsite, and given the unit cost to source test is approximately $3,000-$4,000, this presents an unnecessary cost burden on these facilities. We request that the SCAQMD forego the requirement to source test small boilers and accept the emission certifications as adequate to document NOx emission concentrations for use in the RECLAIM program.

RTU REPORTING

We do not see that the District is proposing any changes to the electronic reporting requirements for NOx Major Sources. The current requirements are specified in 2012 Appendix A, Chapter 7 – Remote Terminal Unit (RTU) Electronic Reporting. This section of the rule requires facilities to use dial-up modem technology to transmit a text string that must be very specifically formatted. The use of dial up modems as telecommunication devices is woefully outdated. It is becoming difficult even to find dial-up modem systems and components since their functionality has been replaced by better technology. Moreover, the very specific text file formatting is very challenging and error prone whenever text files must be written for transmittal to correct previously reported emissions. We have wasted hours of time working with this antiquated system which is still required by the regulation. We urgently request that the District update their electronic reporting system to allow more modern and easy to use technology.

CONCLUSION

Thank you for considering these comments. We would be glad to meet with you and the RECLAIM team to discuss these important issues. Should you have any questions or concerns, please contact me at (949) 248-8490 x511.

Sincerely,

Kathy Prokey

Kathy Prokey
Sr. Engineer
Yorke Engineering, LLC
(949) 248-8490 x225

cc: Judy Yorke, Yorke Engineering, LLC
Pete Moore, Yorke Engineering, LLC
Russ Kingsley, Yorke Engineering, LLC

CHARLES F. TIMMS, JR.
ATTORNEY AT LAW
445 SOUTH FIGUEROA STREET, 31ST FLOOR
LOS ANGELES, CA 90071-1630
TELEPHONE: 213-489-6868
FACSIMILE: 213-489-6828
EMAIL: cftimms@aol.com

August 21, 2015

BY EMAIL AND U.S. MAIL

Philip M. Fine, Ph.D.
Deputy Executive Officer
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765

Re: Comment Letter on NOx RECLAIM Shave Proposal; Cities of Burbank and Pasadena

Dear Dr. Fine:

On behalf of the City of Burbank, Department of Water and Power ("BWP"), and the City of Pasadena, Water and Power Department ("PWP) (collectively "the Cities"), we are submitting the following comments on your staff's draft proposed amendments to Regulation XX, Regional Clean Air Incentives Market ("RECLAIM") ("NOx shave proposal"), published on July 21, 2015. While the NOx shave proposal appears to include provisions that would mitigate some of its worst impacts on the Cities' well-controlled power plants, it still does not provide the needed certainty that adequate RECLAIM Trading Credits ("RTCs") will be available at a reasonable price to cover these plants' anticipated emissions and other needs related to resource adequacy and utility-specific operating contingencies. We would like to suggest some improvements to the proposal that would provide the needed certainty and address other issues.

Both Cities operate their own power plants containing peaking units, and BWP also operates the Magnolia Power Plant ("MPP"), a baseload unit, on behalf of the Southern California Public Power Authority ("SCPPA"). Participants in MPP include Burbank, Pasadena, and four other municipalities. The Cities operate these power plants to serve their municipal customers. RTCs are required not only to cover anticipated annual emissions, but also to meet resource adequacy needs and prepare for utility-specific operating contingencies, such as grid reliability, increased cycling to support integration of renewables, and potential electrification of the transportation system. Unlike other industrial facilities operating under the RECLAIM program, the Cities' power plants are obligated to operate to serve load. If they are unable to serve load, there may be blackouts with serious adverse economic and other consequences.

The staff proposal would require a 47% reduction in the NOx RTC allocations for these power plants. The proposed reductions are so severe that insufficient RTCs would remain to cover Pasadena's and MPP's anticipated emissions, not to mention RTCs needed for resource adequacy and utility-specific operating contingencies.

As you know from our discussions during the Working Group process preceding the proposal, the Cities have requested that their power plants be excluded from the proposed NOx shave. This request is rooted in history and fairness. The Cities have already achieved the goals of the RECLAIM program, and more should not be asked of them.

The Cities have already reduced NOx emissions as much as feasible with the installation of Best Available Control Retrofit Technology ("BARCT") at their existing units, at a cost of over $28 million. In fact, these reductions were achieved over ten years ago pursuant to a command-and-control rule, Rule 2009. These reductions were required in the wake of the energy crisis of 2001, which led to an increase in power plant operation for which adequate RTCs were not available. BWP also has installed Best Available Control Technology ("BACT") at its Lake 1 unit and at MPP, and PWP has under construction a boiler replacement project that also will have BACT installed. The Cities cannot make any further cost-effective NOx emissions reductions. When and if the shave results in a shortage of RTCs to cover operating needs, the Cities would not have the option of installing more control equipment. Instead, all they could do is purchase additional RTCs, if available, or fail to meet load.

Moreover, the Cities are ahead of schedule in meeting the state's requirement that all electricity retailers serve at least 33% of their load with renewable energy no later than 2020. Burbank is already at 34% renewables, and Pasadena is at 28% renewables with a goal of reaching 40% by 2020.

While the Cities therefore believe they should not be subject to the proposed NOx shave, they acknowledge that with appropriate safeguards, the potential adverse impacts of the proposed shave on the Cities' power plants could be substantially avoided. It appears that the staff proposal addresses one important adverse impact: the requirement that MPP hold enough NOx RTCs to cover its maximum rated capacity at the beginning of each compliance year ("NSR holding requirement"), in the face of a 47% reduction in its NOx allocations. The proposal would apparently relieve MPP and other "new," post-1993 facilities from that requirement by providing for an "Adjustment Account" that will meet this requirement on a programmatic basis [see Proposed Amended Rule ("PAR") 2002(f)(4)]. But the proposal only partly addresses the other major potential adverse impact: the prospect that adequate NOx RTCs will not be available at a reasonable price to cover these power plants' anticipated emissions and other needs related to resource adequacy and utility-specific operating contingencies.

In the remainder of this letter, we will address these potential adverse impacts, and other issues as well.

1. Power Plants Need Quicker Access to Non-tradable/Non-usable NOx RTCs If Needed to Cover Annual Emissions

The staff proposal provides for a non-tradable/non-usable adjustment factor to be reflected in the permit for each facility subject to the 47% shave, including power plants, topping out at 0.335 in 2022 [PAR 2002(f)(1)(C)]. As we understand the proposal, it means that up to a 0.335 fraction of each facility's current allocation of RTCs would be made usable and tradable, and therefore available to cover annual emissions, in the event that the Executive Officer determines that the 12-month rolling average price of NOx RTCs exceeds $15,000 per ton (or $7.50 per pound) and after the Governing Board concurs in that determination [PAR 2002(f)(1)(F)]. No fee would be charged for these additional RTCs.

Based on the experience of power plants during the energy crisis of 2000-2001, this cumbersome, two-step process for releasing these RTCs to cover annual emissions appears to be too slow to avoid skyrocketing spot prices or an outright shortage of RTCs for power plants to either cover annual emissions or demonstrate resource adequacy. We understand that the Los Angeles Department of Water and Power will be presenting a more detailed description of how the two-step process for releasing RTCs during the energy crisis of 2000-2001 did not avoid high prices and shortages of RTCs at that time.

The Cities therefore suggest that a provision be added allowing power plants to request that some or all of this pool of non-tradable, non-usable RTCs be converted to usable but non-tradable RTCs, in exchange for a fee of $7.50 per pound. Once converted, the RTCs could be used to cover annual emissions or meet resource adequacy needs for the year in which the request is made, but they could not be traded. In addition, the power plant also would not be allowed to trade any of its own RTC allocation for the year in which the request to convert is made.

The fee serves two purposes. First, it gives power plants the incentive to rely on the RTC market if the spot price remains below $7.50 per pound. As long as the spot price of RTCs remains below that level, power plants will not have an economic incentive to make a request to convert. Instead, they will rely on the RTC market to acquire additional needed RTCs. But if the spot price rises above $7.50 per pound, then they will have an incentive to make a request, if they deem it prudent to do so. Of course, power plants would be free to wait for the slower two-step process to unfold regarding the 12-month rolling average price, and obtain additional unrestricted RTCs without a fee, if they deem that to be the more prudent course.

The fee also serves the purpose of providing the District with funds to achieve additional NOx reductions from other sources, including mobile sources, for which cost-effective reductions cannot otherwise be obtained.

We understand that in response to questions posed at the Working Group meeting on August 19, District staff indicated it is their intention that the non-tradable, non-usable RTCs be removed from each facility's permit after 2022. If these RTCs are indeed removed from the permits, then the suggested provision discussed above would be of little or no use to the Cities, because it is precisely in the last year or two of the NOx shave, and in later years, that these RTCs are most likely to be needed. The Cities therefore also suggest that these non-tradable, non-usable RTCs, or some significant portion of them, remain on power plant permits after 2022.

Attachment 1 to this letter contains an example of rule language that might be used for a provision allowing the conversion of non-tradable, non-usable RTCs to usable but non-tradable status.

2. Power Plants Should Have Access to the "Adjustment Account" to Cover Annual Emissions

As mentioned earlier, the staff proposal contains an "Adjustment Account" enabling post-1993 power plants to meet the NSR holding requirement on a programmatic basis. We understand that staff estimates that 1 to 1 ½ tons of RTCs will be needed for this account [see Draft Staff Report at p. 33]. We suggest that the RTCs in this account also be made available to affected facilities to cover their annual emissions, in exchange for a fee of $7.50 per pound. There does not appear to be any impediment to allowing the RTCs involved to serve both purposes.

As in the case of a request to convert non-tradable, non-usable RTCs to usable but non-tradable RTCs, the fee serves the dual purpose of giving power plants the incentive to rely on the RTC market if the spot price remains below $7.50 per pound, and also providing the District with funds to achieve additional NOx reductions from other sources for which cost-effective reductions cannot otherwise be obtained.

This use of the "Adjustment Account" could be viewed as an alternative to the suggested provision regarding the non-tradable, non-usable RTCs discussed above.

Attachment 2 to this letter contains an example of rule language that might be used to allow RTCs in the "Adjustment Account" to both meet the NSR holding requirement and be available to cover annual emissions.

3. Provisions Involving Delayed RATA Tests Due to Extenuating Circumstances

The Cities appreciate the staff proposal to allow postponement of a relative accuracy test audit ("RATA") when a major source is physically incapable of being operated. [PAR 2012, Appendix A, Attachment C, Section (B)(2)] Allowing postponement by rule provision would make it unnecessary for the Cities to incur the expense of petitioning the Hearing Board for a variance to allow postponement of the test. However, the Cities would like to suggest two changes to the conditions that apply to the postponement.

First, the due date for performing the RATA should be 30 days, rather than 14 days, from the re-firing of the major source. The additional time is needed in some circumstances to perform tests on the source to ensure reliable and safe operation. [See PAR 2012, Appendix A, Attachment C, Section (B)(2)(c)]

Second, the proposed requirement to disconnect and flange the fuel feed lines is unnecessary and costly. The proposed requirement is unnecessary because the fuel meters are required to be maintained, associated fuel records are required to be kept, and stack emissions are continuously monitored and recorded. So there are multiple sources of data to rely on to verify that the source is not operating. The proposed requirement is costly and time consuming because significant manpower and equipment would be needed to meet it. There also may be health and safety risks if asbestos-containing materials are encountered in the work. The Cities therefore suggest that this requirement be deleted. [See PAR 2012, Appendix A, Attachment C, Section (B)(2)(c)]

4. Other Comments and Questions

a. Provisions Involving the Non-tradable, Non-usable Adjustment Factor

i. The staff proposal should be clarified to provide that the 12-month rolling average RTC price that may trigger release of the non-tradable, non-usable RTCs is the "weighted" average. [PAR 2002(f)(1)(E)]

ii. The staff proposal speaks of determining the 12-month rolling average RTC price for all trades in the "current compliance year." It is not clear how this language would apply to a 12-month rolling average price when the 12 months in question straddle two adjacent compliance years. [PAR 2002(f)(1)(E)]

iii. In PAR 2002(f)(1)(F), the correct cross-reference appears to be to PAR 2002(f)(1)(E), not PAR 2002(f)(1)(F).

b. Provisions Involving the "Adjustment Account"

i. The staff proposal includes a provision allowing access to "Adjustment Account" RTCs for the purpose of compliance with annual emissions during a State of Emergency as declared by the Governor. [see PAR 2002(f)(5)] This provision raises several questions:

(1) How is the account to be funded for this purpose, and with what quantity of RTCs? As we indicated earlier, we understand that staff estimates that 1 to 1 ½

tons will be needed to meet the NSR holding requirement. Will additional amounts be added to fund the account to allow compliance with annual emissions?

(2) Why is access to RTCs limited to a State of Emergency declared by the Governor, as opposed to a State of Emergency declared by a local government official, such as a Mayor?

(3) We understand that in response to questions raised at the Working Group meeting on August 19, District staff indicated that RTCs in this account can be used both to meet the NSR holding requirement and to cover annual emissions. If our understanding is correct, then the rule language needs to be clarified.

(4) It may not be appropriate for the Executive Officer to have unfettered discretion to determine the amount and distribution of RTCs. By making these determinations, he would in effect decide which power plants generate electricity during a State of Emergency. Such decisions may be beyond his authority and expertise. It is important, moreover, that every power plant have access to the RTCs it needs to meet its operating requirements.

The Cities appreciate your consideration of these comments. Please let us know if you have any questions.

Sincerely,

Charles F. Timms, Jr.

cc: Jill Whynot, Assistant Deputy Executive Officer (via email)

ATTACHMENT 1

Proposed Amended Rule 2002(f)(1)(G) shall be added to read as follows:

"Notwithstanding the provisions of subparagraph (f)(1)(F), upon the request of a Power Producing Facility, all or a portion of the facility's non-tradable/non-usable NOx RTCs specified in subparagraph (f)(1)(C) shall be converted to usable but non-tradable NOx RTCs for the purpose of compliance with the facility's emissions, or to meet resource adequacy needs, for the year for which the request is made, for a user fee of $7.50 per pound (or $15,000 per ton) of NOx RTCs. Any facility making such a request shall not sell any of its NOx RTC allocation for the year for which the request is made."

Later subparagraphs will need to re-numbered to accommodate this new subparagraph.

ATTACHMENT 2

Proposed Amended Rule 2002(f)(6) shall be added to read as follows:

"Notwithstanding the provisions of subparagraph (f)(5), upon the request of a Power Producing Facility, the Executive Officer shall allow the facility access to Adjustment Account RTCs for the purpose of compliance with the facility's annual emissions, or to meet resource adequacy needs, for a user fee of $7.50 per pound (or $15,000 per ton) of NOx RTCs. These Adjustment Account RTCs are non-tradable. Any facility making such a request shall not sell any of its NOx RTC allocation for the year for which the request is made."

SCEC

August 26, 2015

Philip M. Fine, Ph.D.
Deputy Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, California 91765

Subject: Backstop Measures for Municipal Utilities Operating Under RECLAIM SCEC 2564.2001

Dear Dr. Fine:

South Coast Environmental Company (SCEC) offers the following comments on behalf of the Cities of Anaheim, Colton and Riverside. All three Cities operate power generating stations that are regulated under RECLAIM.

The Cities of Anaheim, Colton and Riverside (the Cities) operate modern facilities that already incorporate Best Available Control Technology (BACT) or Best Available Retrofit Control Technology (BARCT). Municipal power generators have an obligation to provide power to the communities they serve and cannot simply cut back operations due to SCAQMD policies or the implications of SCAQMD's actions on RTC costs and availability. Unlike many facility operators in the South Coast Air Basin that can respond to the proposed NO_X shave by installing new technology or reducing operations, these municipal utilities can only purchase additional NO_X RTCs in order to operate at permitted levels should their existing inventory of credits be discounted. Because of the limited compliance strategies available to municipal utilities and the unique circumstances we face in a regulatory program that is dominated by private sector operators, the Cities feel that they should have been excluded from the RTC reduction proposed by SCAQMD, but we also understand that safeguards can be built into Regulation XX to reduce the impacts of RTC reduction for municipal utilities.

Throughout the rule development process the Cities have stressed that safeguards proposed by SCAQMD to counter the impacts of the RTC reduction must offer certainty that credits will be available when needed, and that those credits can be obtained swiftly and efficiently. The Cities' concerns stem from the uncertainties we will face in the upcoming years as our peaking units are called upon for more frequent run sequences in support of the increased reliance upon renewable resources in the region.

Given that SCAQMD continues to propose a reduction of the Cities' RTC holdings, complementing rule language to ease the burden of the NSR holding requirement for new facilities and to ensure that credits are easily available in the event of RECLAIM or power market upset are critical to the Cities' continued ability to meet their mission as municipal power generators. The Cities appreciate the steps that SCAQMD has taken so far toward meeting the unique needs of municipal power generators, but also recognize that additional thought must be given to several concepts already laid out in Rule 2002. The Cities encourage SCAQMD to continue to refine proposed amendments to Rule 2002 with due consideration of the Cities' needs and we offer these comments for SCAQMD's consideration as it proceeds with its rule development effort.

Rule 2002 (f)(1) - Non-tradable / Non-usable Holdings

SCAQMD proposes to reestablish a non-tradable / non-usable holding account to complement the reduction of available RTCs. Permit holders would be able to access the holding account only after two conditions are met. First the 12-month rolling average RTC price must exceed $15,000 per ton. Second, the SCAQMD Governing Board must direct staff to convert the holdings to tradeable / usable credits.

Responsiveness of Mitigating Actions

The Cities are concerned that rolling average RTC price may trail too far behind sudden RTC price increases and the requirement to obtain Governing Board authorization to convert the holdings to tradeable and useable credits may not be suitably responsive to our needs as municipal utilities. In other words, the Cities' need for certainty and swift access to RTCs may be jeopardized and we will be forced to participate in a market with escalating costs and limited RTC availability until the point that the $15,000 threshold is reached. By the time the SCAQMD responses are implemented, it will be too late to undo the damage to the utilities and local communities.

Request for Flexibility in Accessing Non-tradeable / Non-useable Holdings

The Cities understand that other municipal utilities have suggested to SCAQMD that we should have discretionary use of our non-tradeable / non-usable credits for our own use, but not to be sold or transferred to other entities. Those proposals vary from making the credits available at no cost to making them available for a mitigation fee of $7.50 per pound, which is equivalent to the trigger price of $15,000 per ton. The fee would be paid only if the holdings are accessed prior to the rolling average price being reached. If the $7.50 fee were to be assessed, municipal utilities would in effect, access their non-tradeable / non-useable credits only if spot market prices escalate above that rate and would otherwise rely upon the market for any required RTCs.

The Cities are supportive of the proposals to expand access to credits and believe that they would be beneficial to the utilities, SCAQMD and the RECLAIM program in general. By providing access to these credits in advance of a market upset, SCAQMD would provide municipal utilities the certainty needed to meet our mission at a reasonable cost and the limited access of utilities to their non-tradeable credits may actually prevent market upsets that would trigger the widespread release of non-tradeable / non-useable credits to all RECLAIM operators. Finally, if utilities are assessed a fee of for their use of their non-tradeable / non-useable credits in advance of the 12-month price trigger being reached, the proceeds would be available to SCAQMD to facilitate voluntary NOx emission reductions. Those reductions may be more cost-effective than what would otherwise be obtained within the RECLAIM program.

Sunset of Non-tradeable / Non-useable Holdings

The Cities understand that SCAQMD proposes to discontinue the non-tradeable / non-useable holdings in the year 2022. Given the uncertainty presented by increased integration of renewable resources and regional electrification, the Cities ask SCAQMD to provide for continued utilization of the non-tradeable / non-useable holdings, at least for municipal utilities.

Rule 2002 (f)(4) & (5) RTC Adjustment Account

SCAQMD proposes to establish an RTC adjustment account that would serve two purposes. The first is to provide a store of credits that new power generating facilities can use to demonstrate compliance with the NSR holding requirement of Rule 2005 (Rule 2002 (f)(4)). The second purpose of the adjustment account is to make credits available to all power generators in response to an electrical emergency (Rule 2002 (f)(5)). During the August 19 public consultation, SCAQMD indicated that it plans to further refine the provisions of Rule 2002 that deal with the proposed adjustment account. The Cities suggest that the following concepts be given additional consideration.

Compatibility of Dual Purposes

The Cities appreciate that SCAQMD is proposing alternatives that would ease the NSR holding requirement burden and also provide additional RTCs in the event of an emergency. However, it is not clear that both purposes can be simultaneously served, given the amount of RTCs that SCAQMD proposed to allocate to the account. The Cities ask that SCAQMD clarify how the account can be available for emergency use by all power producers, without jeopardizing the ability of new facilities to make the NSR holding demonstration.

During the working group meeting, SCAQMD advised that the proposed funding level of 1 – 1.5 tons/day reflects the amount of reduced RTCs that are currently held by new facilities for the offset demonstration. If the funding of the account reflects the reduced RTCs, rather than the entire PTE for these facilities, it is unclear how the adjustment account can be used by existing facilities (pre 1993 installations) during an emergency without jeopardizing the ability of new facilities to make the NSR demonstration.

Authority to Declare an Energy Emergency

SCAQMD initially proposed that RTCs in the adjustment account would be available to power generators upon an emergency declaration made by the Governor of California, but has committed to investigate concepts that would allow other parties to make such declarations.

August 26, 2015
Dr. Philip Fine
South Coast AQMD

Additional entities or authorities should be allowed to declare the presence of an energy emergency at both a regional and local level. Many emergencies requiring local power generation may exist within the boundaries of a city and state or regional authorities may not be able to investigate and make the necessary declaration quickly. Local authorities, such as a City Manager or Mayor, should also be allowed to make a declaration that would allow for the release of RTCs from the adjustment account.

Dispersing Credits from the Adjustment Account

It is unclear how access to RTCs would be granted or how competing applicants would be prioritized by SCAQMD to receive RTCs. SCAQMD must further define its role in the process of granting access to the adjustment account if the Cities are to be assured that credits are available not only for the NSR holding demonstration, but also for easy access in case of an emergency.

RTC Management Flexibility

The Cities ask SCAQMD to clarify how the adjustment account would affect the way in which new power producing facilities would manage the remaining RTCs listed in their facility permits, with respect to the Rule 2005 (f) holding requirement. Ideally, provisions to accommodate the holding requirement would also allow facility operators to sell the remaining unused RTCs listed in their permit in advance of compliance year closure. We also ask SCAQMD to give consideration to the same discretionary use of the adjustment account by municipal utilities that is proposed within this letter for the non-tradeable / non-useable holdings.

Thank you for considering these comments. The Cities of Anaheim, Colton and Riverside welcome the opportunity to further discuss SCAQMD's RECLAIM proposal and I am available should you require additional information regarding the Cities' comments.

Sincerely,
SCEC
An affiliate of Montrose Environmental Group, Inc.

Karl A. Lany

Karl A. Lany
Sr. Vice President

cc: Manny Robledo, Electric Operations Manager, Anaheim Public Utilities
Wayne Feragen, Sr. Plant Manager, City of Colton
Reiko Kerr, Assistant General Manager - Power Resources, Riverside Public Utilities
Chuck Casey, Utility Generation Manager, Riverside Public Utilities

2564.2001Rule 2012ltr4.doc

ECOSERVICES

ECO SERVICES OPERATIONS LLC
DOMINGUEZ PLANT
20720 S. Wilmington Avenue
Long Beach, CA 90810
TEL: (310) 637-8080
FAX: (310) 603-9077

August 28, 2015

Via E-mail: jcassmassi@aqmd.gov

Mr. Joe Cassmassi
Planning & Rules Manager
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765-4182

RE: PROPOSED AMENDMENTS TO REGULATION XX:
NOx SHAVE FOR RECLAIM SOURCES

Dear Mr. Cassmassi:

Eco Services Operations LLC (Eco Services) is again writing to express its concerns with the South Coast Air Quality Management District's (SCAQMD's) proposed amendments to Regulation XX to implement the latest round of NO_x emissions reduction for RECLAIM sources ("NO_x shave"). Eco Services owns and operates a sulfuric acid regeneration plant located at 20720 South Wilmington Ave in City of Carson (Dominguez Plant). Eco Services provided comments to you by letter dated April 27, 2015 and is attaching a copy of our prior comments for your reference.

As we previously advised, the Dominguez Plant has been an active supporter and participant of the RECLAIM program. In 2010, Eco Services worked cooperatively with the SCAQMD to identify the Best Available Retrofit Control Technology (BARCT) for the control of SOx emissions and installed a caustic scrubber to greatly reduce SOx emissions at a substantial cost. Eco Services is committed to environmental compliance as demonstrated through our implementation of BARCT for SOx.

As the SCAQMD develops amendments to the RECLAIM program for NOx, Eco Services reiterates its commitment to environmental compliance and working cooperatively towards a common sense and practical solution. Eco Services believes that implementation of technically feasible and cost-effective measure is appropriate. Eco Services is amenable to implement any such measures as we have done with SOx emissions. However, based on the SCAQMD's BARCT analysis, there are no technologies that qualify as BARCT for the NOx emissions sources at the Dominguez Plant. Accordingly, Eco Services is left in the unenviable position of having no practical means of complying with RECLAIM other than purchasing additional allowances at a substantial cost.

Eco Services is very concerned with the prospect of having no control over its ability to comply with RECLAIM. Importantly, we have been advised by RECLAIM brokers that the drastic across the board shave being contemplated by the SCAQMD will result in NOx credits being rendered extremely scarce and accordingly, cost prohibitive. In order for a cap-and-trade program to function properly, there must be a reasonable amount of credits available for trading at a reasonable cost. It is our understanding that NOx credits, if available for trading at all, will be exorbitantly priced.

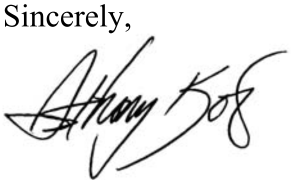
Eco Services simply does not support a program that leaves no reasonable means of complying other than to put us at the mercy of what we believe will be a dysfunctional trading program. Instead, as we have demonstrated with respect to the SOx RECLAIM program, we support revisions to the RECLAIM program that rely on implementation of feasible and cost-effective controls. Sources that can implement BARCT can and should do so as a first step towards additional reductions. We strongly urge the SCAQMD to consider this approach which will result in a reduction of NOx emissions based on cost-effective controls which will not cripple the RECLAIM trading program and leave smaller emitters no real cost-effective option for compliance. If the SCAQMD pursues the across the board shave, it will effectively be imposing cost-effective requirements on the BARCT sources but not considering cost-effectiveness at all for non-BARCT sources. Eco Services believes that is inequitable and inappropriate.

If the SCAQMD does pursue an across the board NOx shave, Eco Services recommends that the changes to RECLAIM include some type of measure to limit the costs of NOx credits in addition to the current $15,000 per ton annualized average cost, particularly for small emitters. An equitable rule should provide the regulated community with a cost-effective means of complying. We request that the SCAQMD somehow provide a ceiling on the financial impact it will have on RECLAIM participants in terms of cost-effectiveness. BARCT sources will be subjected to cost-effective controls. Similarly, the financial impact to non-BARCT sources should also be based on cost-effectiveness.

It is our understanding that Non-Tradable/Non-Useable allocations will be issued to emitters, and that these "safety valve" allocations can be used as compliance instrument when the average cost of annual NOx RTC exceeds $15,000 per ton (or $7.50 per pound). However, we believe that the time for cost averaging should be significantly shortened to prevent the repeat of situation similar to year 2000 when the value of annual NOx RTC went far above the $7.50 per pound threshold. Also, additional safe guards should be considered to prevent non-compliance for non-BARCT sources if the NOx RECLAIM market fails such that no NOx RTCs are available to be purchased.

If you have any questions or need additional details regarding the information contained in this letter, please contact me at (925) 313-8221.

Sincerely,



Anthony Koo
Sr. Environmental Engineer

cc: Philip Fine, Ph.D., Assistant Deputy Executive Officer, pfine@aqmd.gov
Jill Whynot, Assistance Deputy Executive Officer, jwhynot@aqmd.gov
Gary Quinn, P.E., Program Supervisor, gquinn@aqmd.gov
Kevin Orellana, Air Quality Specialist, SCAQMD, korellana@aqmd.gov

Encl.
{B2213377.1}

ECOSERVICES

ECO SERVICES OPERATIONS LLC
DOMINGUEZ PLANT
20720 S. Wilmington Avenue
Long Beach, CA 90810
TEL: (310) 637-8080
FAX: (310) 603-9077

April 27, 2015

Via E-mail: jcassmassi@aqmd.gov

Mr. Joe Cassmassi
Planning & Rules Manager
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765-4182

RE: PROPOSED AMENDMENTS TO REGULATION XX:
NOx SHAVE FOR RECLAIM SOURCES

Dear Mr. Cassmassi:

Eco Services Operations LLC (Eco Services) is writing to express its concerns with the South Coast Air Quality Management District's (SCAQMD's) proposed approach to amending Regulation XX to implement the latest round of reductions in NO_x emissions allowances for RECLAIM sources ("NO_x shave").

Eco Services owns and operates a sulfuric acid regeneration plant (Dominguez Plant) located at 20720 South Wilmington Ave. in City of Carson. The Dominguez Plant's sulfuric acid product is primarily used in petroleum refineries as alkylation catalyst to produce high octane, low vapor pressure, and clean burning gasoline blending stock.

The Dominguez Plant has been an active supporter and participant of the SCAQMD RECLAIM Program. During the 2010 SO_x RECLAIM rulemaking process, Eco Services worked closely and cooperatively with SCAQMD in identifying feasible Best Available Retrofit Control Technology (BARCT) for the Plant. In 2012, the facility became the world's first double absorption sulfuric acid plant to be retrofitted with a caustic scrubber to reduce SO_x emissions. The scrubber has been in operation since November of 2012 and has since been consistently removing approximately 1 ton of SO_x per day from the South Coast Air Basin. These examples serve as a clear indication of Eco Services' commitment to environmental compliance and air quality improvement.

We understand that the SCAQMD is implementing its Air Quality Management Plan (AQMP) and plans to reduce NO_x emissions from its Air Basin. SCAQMD is contemplating on reducing as much as 50% of the currently-available NO_x credit from the Regional Trading Credit (RTC) universe. More importantly, SCAQMD is in the process of evaluating various options on how the reductions will be implemented, including an across-the-board shave approach that would uniformly remove RTCs without consideration of an individual source's operational characteristics or its ability to implement BARCT fundamentally developed for other types of sources.

In 2014, SCAQMD conducted a detailed BARCT study of the major NO_x emitting sources within the South Coast Air Basin. The study did not include the Dominguez Plant because there is no known BARCT available to reduce NO_x emissions at sulfuric acid plants. Furthermore, the study also concluded that the other two natural gas burning sources (the preheater and package boiler) at the Dominguez Plant were not cost-effective for BARCT implementation due to their low usage and NOx emissions.

The Dominguez Plant emits about 0.0685 tons per day of NO_x, which matches its RTC allocations without any surplus. This total represents 0.258% of the entire current NO_x RTC market. Eco Services is concerned that if a 50% across-the-board shave is implemented, it will severely inhibit the Dominguez Plant's ability to comply with the RECLAIM Program. Without a viable BARCT and limited RTC supply, Eco Services is concerned that it will be difficult, if not impossible, for the Dominguez Plant to comply with the post-shave allocation. Assuming that NO_x credits will be available, based on the current credit value of $90 per pound, this translates to an exorbitant minimum of $4,500,000 in compliance costs for the Dominguez Plant.

Eco Services respectfully asks SCAQMD to seriously consider the huge negative impacts to small emitters like the Dominguez Plant, which have no viable options to comply with the proposed NO_x reductions if implemented. Instead, Eco Services urges SCAQMD to consider achieving this round of NO_x reductions by using the sector and subsector approach in lieu of an across-the-board shave. In particular, Eco Services believes that this iteration of the NO_x shave should only be applied to sectors which have viable BARCTs that were identified in the recent BARCT study conducted by the SCAQMD. Applying such an approach, Eco Services respectfully requests that the District remove the Dominguez Plant from the list of facilities subject to this round of the NOx shave.

If you have any questions or need additional details regarding the information contained in this letter, please contact me at (925) 313-8221.

Sincerely,

Anthony Koo
Sr. Environmental Engineer

cc: Elaine C. Chang, D.Ph., Deputy Executive Officer, echang@aqmd.gov
Philip Fine, Ph.D., Assistant Deputy Executive Officer, pfine@aqmd.gov
Jill Whynot, Assistance Deputy Executive Officer, jwhynot@aqmd.gov
Gary Quinn, P.E., Program Supervisor, gquinn@aqmd.gov
Kevin Orellana, Air Quality Specialist, SCAQMD, korellana@aqmd.gov

→ Joe

CHARLES F. TIMMS, JR.
ATTORNEY AT LAW

445 SOUTH FIGUEROA STREET, 31ST FLOOR
LOS ANGELES, CA 90071-1630

TELEPHONE: 213-489-6868
FACSIMILE: 213-489-6828
EMAIL: cftimms@aol.com

September 17, 2015

BY EMAIL AND U.S. MAIL

Philip M. Fine, Ph.D.
Deputy Executive Officer
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765

Re: Follow-up to Comment Letter on NOx RECLAIM Shave Proposal; Cities of Burbank and Pasadena

Dear Dr. Fine:

On behalf of the City of Burbank, Department of Water and Power ("BWP"), and the City of Pasadena, Water and Power Department ("PWP) (collectively "the Cities"), we are submitting this follow-up letter to our August 21, 2015, comment letter on your staff's draft proposed amendments to Regulation XX, Regional Clean Air Incentives Market ("RECLAIM") ("NOx shave proposal"), published on July 21, 2015.

We have identified some additional rule language that would need to be amended to facilitate our proposal that power plants be provided with quicker access to non-tradable/non-usable NOx RTCs, and/or access to RTCs in the Adjustment Account, if needed to cover annual emissions. This additional language will ensure that the relevant RTCs are only credited to the SIP on a year-by-year basis to the extent they are not needed for power plant compliance purposes. See Attachment 1 to this letter.

In addition, the Cities support the proposal of the Los Angeles Department of Water and Power to expand the emergency provisions in the staff proposal to allow power plants to access RTCs in the Adjustment Account if an energy emergency alert is declared by the relevant electrical "Reliability Coordinator." See Attachment 2 for proposed rule language.

The Cities appreciate your consideration of these additional comments. Please let us know if you have any questions.

Sincerely,

Charles F. Timms, Jr.

cc: Jill Whynot, Assistant Deputy Executive Officer (via email)
Attachments.

ATTACHMENT 1

Proposed Amended Rule 2002(f)(1)(J) shall be amended to read as follows:

"The NOx RTC adjustment factors for compliance years 20019 through 2021 shall not be submitted for inclusion into the State Implementation Plan until the adjustments have been in effect for one full compliance year. The 2022 NOx RTC adjustment factors shall not be submitted for inclusion in the State Implementation Plan until 12-months after the adjustments have been in effect for one full compliance year. <u>At the end of each compliance year reconciliation period from 2022 and each year thereafter, the Power Producing Facility shall surrender unused non-tradable RTCs to the District for inclusion into the State Implementation Plan.</u>"

ATTACHMENT 2

Proposed Amended Rule 2002(f)(5) shall be amended to read as follows:

"During a State of Emergency as declared by the Governor or an Energy Emergency Alert as declared by the Reliability Coordinator, the Executive Officer will allow Power Producing Facilities access to Adjustment Account RTCs for the purpose of compliance with the annual emissions. ~~These available RTCs will be limited to those that are in excess of those specified for use in paragraph (f)(4).~~ The amount and distribution of the RTCs will be determined by the ~~Executive Officer~~ Power Producing Facilities based on the ~~impact that~~ amount of energy they produce during the State of Emergency ~~has on the RECLAIM program~~ or the Energy Emergency Alert."

'Reliability Coordinator' means the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System as defined in the North American Electric Reliability Corporation Glossary."

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL℠ Company

Mr. Joe Cassmassi
Director, Planning and Rules
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

RE: 2015 RECLAIM

Dear Mr. Cassmassi:

Southern California Edison (SCE) appreciates the opportunity to comment on the South Coast Air Quality Management District's (District) proposed reduction of Reclaim Trading Credits (RTCs). Moving the District's air basins into attainment is a step toward improved air quality and improved economic growth by increasing the ability of businesses to operate in this region. The District's proposed reduction in the RTC market should act to drive stationary sources under the RECLAIM program to install Best Available Retrofit Control Technology (BARCT) for control of NOx emissions. SCE recognizes the need to make reductions in NOx in order to assist in the effort to achieve attainment with the National Ambient Air Quality Standards.

The shave should drive sources towards BARCT

The shave, as proposed, would constitute a 53% reduction in the total number of RTCs in the market. 67% would be taken from the refinery sector while 47% would be taken from the non-refinery sector, including electric generation facilities. While this would be better than an outright across-the-board shave, it still would trigger costs for the electric generation sector that would have no commensurate impact on reducing air emissions. The electric generation facilities are already at Best Available Control Technology (BACT) with no existing opportunity to reduce emissions (other than curtailing operation, which is not feasible for electric generation facilities since electric demand will dictate operating times). While there is recognition there will have to be some reduction of RTCs from electric generation facilities, the shave should cause facilities not currently at BARCT to install better controls. With the proposed percentages, the costs will disproportionally impact facilities that are already at BACT and result in a subsidization by those at BACT of facilities not yet utilizing the best controls.

The proposed shave amount on the Electric Generation Facilities in effect caps the amount of fuel we can use

As stated above, SCE's electric generation facilities are already at BACT or BARCT, with no currently feasible opportunity, from a control standpoint, to reduce emissions further. With no advancements in control technology, the only way to further reduce emissions is by curtailing operation (i.e. limiting fuel usage). Thus, if no credits were available for purchase on the open market, which is a possibility given the proposed size of the shave, the only way to stay in compliance would be by reducing fuel usage.

P. O. Box 800
2244 Walnut Grove Ave.
Rosemead, CA 91770

Limiting operations might be an option in other industries where production can be outsourced to different sites, but this is not an option for electric generation facilities, as local demand for electricity dictates when these facilities must operate, as ordered by the California Independent System Operator (CAISO). Existing contracts with the California Public Utilities Commission (CPUC) also require the facility to operate when the grid demands it, meaning that when this equipment will run, is effectively out of SCE's control. In other words, if system demand requires SCE to turn on a unit, the facility must do so. SCE will not violate the air permit conditions. But failure to operate when needed for system demand could result power outages.

It should also be noted that under the California Health & Safety Code for market-based programs [§39616(c)], a program must not result in disproportionate impacts to stationary sources in the program as compared to other permitted stationary sources not in the program. A typical permitted source not in the RECLAIM program is subject to rule-based command and control regulations. Were SCE's facilities not in the RECLAIM program, command and control regulations would require BACT concentration limits with no further limits on operation or fuel use, unless such further limits were agreed to for PTE or CEQA limit purposes. However, because the facilities are in RECLAIM, not only are they subject to BACT, but also to the holding requirement and the potential surrender of RTCs. The result is that if there aren't enough RTCs in the market, this proposed shave would effectively cap fuel use. By setting a concentration limit as well as a fuel use limit, this proposed shave would go beyond command and control regulations.

The amount of the shave could have impacts on grid reliability during emergency situations.

The current proposal contemplates what amounts to a 53% shave in the existing RTC market. While action must be taken to reduce current NOx emissions, this action must not result in a situation where generating facilities are unable to operate during emergency situations. The electric grid is a complex, interrelated system. All components work together to generate and ultimately distribute electric power to end users. If, for example, a major transmission line were to go down, there would be an immediate need for local, dispatchable generation to begin operating. If these facilities don't have sufficient RTCs to operate in these circumstances, the system would be faced with energy resources that could not be operated under SCAQMD rules, which would result in load curtailment. Because of the complexity of the system, there is no bright line that can be drawn. The District must therefore exercise caution and not bring about a market that is incapable of responding to emergency situations.

Changes to the RATA testing requirements are supported

Thank you for meeting previously with SCE and DWP on this matter and recognizing that there was a legitimate need to change the rule language regarding postponement of RATAs. In the past, SCE has experienced multiple incidents where equipment has failed in the quarter in which a RATA was due, and found that the District's options for RATA postponement were impractical. With no reasonable alternative to postpone testing, and in order to avoid enforcement, the facilities were forced to petition the SCAQMD Hearing Board for variances. SCE believes the proposed language addresses this issue and now provides a legitimate alternative for RATA postponement without variance relief.

While we fully support the option presented, we are requesting an increase of the 14 unit operating day extension to 30 unit operating days. The main concern is with SCE's Pebbly Beach Generating Station on Catalina Island. Due to its remote location, weather related delays of transportation options to the island, and the high work load schedule of our source testing firm, it can be difficult to organize a RATA test in a short timeframe. The testing firm must separately schedule a time to barge its equipment out to the island, and if power demand on the island were high, the engines may need to run as soon as possible when they return to service, which could impact the test protocol This is especially true for the cleaner engines, as they must operate more frequently in order to comply with facility-wide emission limits. If the source testing firm could not schedule a visit to the island and the engines had to operate to support the power demand, 14 operating days might not be enough time to complete an appropriate RATA. As an alternative, if staff is not open to extending the 14 unit operating day window, SCE suggests having an equivalent operating hour limit. This could give the facility more time to schedule a test without increasing the overall operating time of the unit. Whether there are 14 days or 30 days to complete a RATA, a facility has plenty of incentive to complete the RATA as soon as possible so as to minimize the use of missing data procedures. We ask that the District consider this extension. But other than this amendment, we fully support the rule language as presented by the District and we appreciate the work done by staff to address this issue.

SCE Supports the adjustment account for compliance with Rule 2005 Subdivision (f). Existing USEPA interpretation of the NSR requirements hold that a facility in RECLAIM must obtain sufficient RTCs at the beginning of the calendar year to cover the total potential to emit (PTE) for the year notwithstanding that most facilities do not operate at or near their PTE. This results in a substantial procurement of RTCs that are necessarily bought at a time they are most expensive, but if not used are then sold off when they are of little value. Further, there is no environmental benefit created by what is, in effect, an over-procurement of credits. SCE supports the proposal by the District to create an adjustment account that would cover this RTC requirement. It would eliminate the costly procurement of RTCs beyond what is really needed to cover actual emissions and, quite simply, it makes sense. We urge the District to continue to seek EPA concurrence with this proposal.

As stated above. SCE appreciates the opportunity to provide these comments and we can make ourselves available, if needed, to further clarify our positions. We look forward to working with the District on this important issue.

Sincerely,

Thomas Gross

Thomas Gross

GE
Capital

Mark Mellana
General Manager, Inland Empire Energy Center
800 Long Ridge Road
40434260E
Stamford, CT 06927
USA

T 203 326-7355
mark.mellana@ge.com

September 22, 2015

Ref. No. GE/IEEC – 0905

Joe Cassmassi
Rules and Planning Manager, Planning Rule Development, and Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Subject: Inland Empire Energy Center, LLC Request to Change Designation from Investor Category to the Power Plant Category
RECLAIM XX Rule Making

Dear Mr. Cassmassi:

Inland Empire Energy Center, LLC (IEEC, LLC), a wholly-owned subsidiary of General Electric (GE), is the permit holder for the Inland Empire Energy Center (IEEC). GE partnered with Calpine in 2005 to bring the H-technology gas turbine to life as a demonstration project at the IEEC. For business reasons that existed at the time, GE purchased all NOx RECLAIM Trading Credits (RTCs) required for the IEEC instead of having them purchased directly by IEEC, LLC. The NOx RTCs were acquired specifically and solely to meet the RECLAIM compliance obligations of IEEC, and have been used for no other purpose throughout the life of the project. GE has no interest in any other RECLAIM facility. The GE RTC account is, and always has been, 100% dedicated to the IEEC (please see attachments for evidence of past account transfers).

The current staff proposal for amending South Coast Air Quality Management District (District) Regulation XX incorrectly categorizes the IEEC RTCs held by GE in the Investor category. As the name suggests, the Investor category includes entities that buy and sell RTCs with the objective of making a profit based on fluctuations in market price. The Investor held RTCs are disassociated from any RECLAIM facility. This is clearly not the situation with respect to the IEEC RTCs held by GE.

We suspect that this error occurred because IEEC, LLC is the permit holder for the IEEC, not GE. However, this legal distinction does not change the fact that the subject RTC account is exclusively associated with the IEEC, and is not an Investor account. Because all of the GE owned NOx RTCs were acquired and are used solely for IEEC compliance purposes, GE's NOx RTC account should be designated as a Power Plant (non-refinery) account for purposes of the allocation "shave" in the proposed amendments to Regulation XX.

Failing to correctly categorize the allocations held by GE for IEEC would result in a double digit multi-million dollar impact on our business. IEEC, LLC and GE could have never known that the means by which they chose to acquire and hold the RTCs for the IEEC could have such serious implications, and we do not believe that the District intends such an unforeseen consequence. We therefore request that the GE RTC account be correctly categorized as a Power Plant (non-refinery) account by changing Table 8 in proposed Rule 2002 from Inland Empire Energy Center, LLC to "General Electric Company, Inland Empire Energy Center, LLC

Thank you for your attention to this matter. If necessary to resolve this matter, we would be happy to meet with you and your team to discuss the details of our request. Please coordinate directly with Alisa Moretto at 951-226-4553.

Sincerely,

Francisco Escobedo for

Mark Mellana
General Manager
Inland Empire Energy Center, LLC

cc: Alisa Moretto
Roy Belden

GE
Energy

Tisha Monaco
Sr. Administrative Assistant

Inland Empire Energy Center
26226 Antelope Road
Romoland, CA 92585
USA

T 951 928 5905
Tisha.monaco@ge.com

March 12, 2009

Ref. No. GE/IEEC – 0308

Ms. Susan Tsai
RECLAIM Administration – RTC Transfers
South Coast Air Quality Management District
21865 E. Copley Dr.
Diamond Bar, CA 1765

RE: Inland Empire Energy Center – Form 2007-1 for Delegation of Authority for RTC Transfers & Credits – ID #129816

Dear Susan,

Per our conversation on Tuesday, March 10, 2009, Attached you will find form 2007-1 filled out to make this change giving Delegation of Authority to Francisco Escobedo & Ken Kohl to make RTC Transfers & Credits under ID #129816.

If you have any questions or needs, please do not hesitate to contact me at 951 928 5905.

Thank you,

Tisha Monaco
Sr. Administrative Assistant

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

AQMD

Regional Clean Air Incentives Market Trading Account Representative Registration and Certification Form

Form 2007-1

This form is used to identify the authorized account representative(s) for an RTC holder and/or certify the account status for an RTC trader.

Section I - Account Information

Account Name Inland Empire Energy Center, LLC **Account I.D..#** 129816 (If known)

Account Street Address
26226 Antelope Rd.
Street # 1

Street # 2

Romoland, CA 92585
City, State Zip

Country (if not in the United States)

Mailing Address for Transaction Confirmations
26226 Antelope Rd.
Street # 1, or P.O.Box

Street # 2

Romoland, CA 92585
City, State Zip

Country (if not in the United States)

Section II - Designation of Representatives

Name	Title	Signature	Date
Francisco Escobedo	Director, Asset Managment	Francisco Escobedo	3-12-09
Phone # (951) 928 -5941	Fax # (866) 749 - 9109		
Ken Kohl	Owners Engineer	Ken Kohl	3-11-09
Phone # (518) 385 - 4290	Fax # (999) 221 - 3549		
Phone # ( ) -	Fax # ( ) -		

Section III - Certification Status

I certify that the above named entity is (check boxes below that apply):

Yes	No	
☐	☒	a) Domiciled in the State of California[1]
☒	☐	b) A holder of an active RECLAIM Facility Permit
☐	☒	c) A holder of a pending RECLAIM Facility permit application

If any box is checked "Yes", proceed to Section IV and complete. If all boxes are checked "No", complete Section IV and Attachment A – Designation of Agent for Service of Process and Consent to California Jurisdiction Form

[1] Domiciled in the State of California for the purposes of this form shall be deemed: a) for natural individuals - having permanent and primary residence located in the State of California; (b) for a corporation, firm, association, organization, partnership, business trust or other business entity - incorporated or created pursuant to the laws of the State of California, and in good standing according to the Secretary of the State of California, or (c) for any State or local governmental agency, any subdivisions thereof, or any public district - created and existing pursuant to California State, or local governmental laws and regulations.

Section IV - Certification of Owner or Officer

I certify that I am an owner or officer of the account identified and authorize the above parties to act as the company's representatives in the registration of any transactions for RTCs for the Facility identified herein. I am authorized to make this submission on behalf of the persons with an ownership interest for whom this submission is made. I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on 3/12/09 (*Date*) at 10:00 a.m. Romoland, CA, USA (*City, State, Country*)

Francisco Escobedo (*Name*) Director, Asset Mgmt. (*Title*) (951) 928 - 5941 (*Telephone*) Francisco Escobedo (*Signature*)

This form and SCAQMD's use shall not constitute any acceptance of liability on behalf of SCAQMD for any RTC transaction which may be the result of misrepresentation or error by trading partners or their representatives. This form and SCAQMD's use of it shall not be construed, in any way, to create a fiduciary relationship between it and either the seller or buyer of RTCs or with any other party associated with such transactions.

Submit this form and attachments to:

SCAQMD, RECLAIM Administration - RTC Transfers, P.O. Box 4830, Diamond Bar CA 91765-0830

GE
Energy

Francisco Escobedo
Director, Asset Management

Inland Empire Energy Center
26226 Antelope Road
Menifee, CA 92585
USA

T 951 928 5941
Frank.Escobedo@ge.com

June 10, 2014

Ref. No. GE/IEEC – 0849

Reclaim Administration – RTC Transfer
South Coast Air Quality Management District
21865 Copley Dr.
Diamond Bar, CA 91765-0830

SUBJECT: INLAND EMPIRE ENERGY CENTER (IEEC) – 2014 RTC TRANSFER FROM GE ACCT #700126 TO IEEC ACCT #129816

To Whom It May Concern:

Attached is our completed form 2007-2 for the transfer of internal RTC's from the General Electric account #700126 to the Inland Empire Energy Center account #129816. This internal transfer is for the following single year trades:

- 96,380 lbs of Cycle 1, Coastal zone, RTC's Expiring December 31, 2015 at $0.00/lb/year
- 12,340 lbs of Cycle 2, Coastal zone, RTC's Expiring June 30, 2015 at $0.00/lb/year
- 23,600 lbs of Cycle 1, Inland zone, RTC's Expiring December 31, 2014 at $0.00/lb/year
- 35,000 lbs of Cycle 1, Inland zone, RTC's Expiring December 31, 2015 at $0.00/lb/year
- 82,923 lbs of Cycle 2, Inland zone, RTC's Expiring June 30, 2015 at $0.00/lb/year

Since this is an internal transfer, the price is not applicable and there is no purchase agreement or transaction confirmation required.

If you have any questions or need further information, please don't hesitate to contact me at (951) 928-5941.

Sincerely,

Francisco Escobedo

Francisco Escobedo
Director, Asset Management

Enclosure

cc: Christine Stora - CEC

AQMD

South Coast Air Quality Management District

Form 2007-2
Regional Clean Air Incentives Market Trading Credits (RTCs) Transaction Registration

Submit this form and required documents with Transaction Registration Fee pursuant to Rule 301

Mail To:
SCAQMD, RECLAIM Administration - RTC Transfers
P.O. Box 4830
Diamond Bar, CA 91765-0830

Tel: (909) 396-3119
www.aqmd.gov

Name of Buyer/Transferee: Inland Empire Energy Center, LLC — Account I.D. #: 129816

Name of Seller/Transferor: General Electric Company — Account I.D. #: 700126

Pollutant: ⊙ NOx or ○ SOx *(Identify one pollutant only)* — Is this part of a Swap transaction? ○ Yes ⊙ No

Is this form reporting the trade of an Infinite-Year-Block of RTCs? ⊙ No ○ Yes

If "Yes," Total Value of Transaction $ N/A ; Enter N/A in the "Price" column below; Report in this form only those RTCs that are traded as part of a single negotiated price. File separate forms to transfer any other RTCs that were negotiated for a separate price.

(Attach a separate form if more than 8 transfers are being registered)

Terms of RTC Transferred			Original Zone (Coastal or Inland)	Quantity (Pounds/year)	Price* ($/Pound)	Use Code (Buyer)	Generation Code (Seller)	Account Source Code (Seller)	Origin of Credits (Seller)	Certificate Serial Number (Seller)
Cycle	From Compliance Year*	To Compliance Year*								
1	12/31/2014	Single Year Trade	Inland	23,600	N/A	01	N/A	B	REGXX	N/A
2	6/30/2015	Single Year Trade	Coasta	12,340	N/A	01	N/A	B	REGXX	N/A
2	6/30/2015	Single Year Trade	Inland	82,923	N/A	01	N/A	B	REGXX	N/A
1	12/31/2015	Single Year Trade	Coasta	96,380	N/A	01	N/A	B	REGXX	N/A
1	12/31/2015	Single Year Trade	Inland	35,000	N/A	01	N/A	B	REGXX	N/A

* In the "From Compliance Year" Column, fill in the expiration date of the first compliance year RTCs. The "To Compliance Year" Column is used to enter (1) single year transaction, (2) perpetual stream transaction, or (3) multiple year transaction of RTCs of same zone, quantity, and price in a single line. For a single year transaction, mark this column "Single Year Trade". For a perpetual stream transaction, mark this column "All Years After". For a multiple year transaction, fill in the expiration date of the last compliance year. Use separate lines for transactions of different RTCs, quantities or prices. Transactions for all inclusive years between these two columns will be registered. **See reverse side for examples.**

Buyer Use Codes *(only one code per transaction)*

- 01 Increase RTC Allocation account balance to satisfy annual compliance
- 02 Use under Rule 2005 - New Source Review for RECLAIM
- 03 Increase RTC certificate account balance without issuance of physical certificate.
- 04 Increase RTC certificate account balance with issuance of physical certificate
- 05 Retire RTCs from market without issuance of physical certificate
- 06 Retire RTCs from market with issuance of physical certificate
- 07 Facility Acquisition (Change of Ownership)

NOTE: RTCs in Certificate or Printed Certificate Account must be transferred to Allocation Account to be eligible for compliance use.

Seller Generation Codes

- 01** Process Change
- 02** Addition of Control Equipment
- 03** Production Decrease
- 04** Equipment or Facility Shutdown
- 06 Facility Acquisition (Change of Ownership)
- 07 RTCs for Future Compliance Year, cause of generation not yet been determined

*** Selection of this Generation Code must be accompanied by the selection of Account Source Code "A" - Allocation Account.*

Seller Account Source Code *(only one code per transaction)*

- A Allocation Account
- B*** Certificate Account
- C*** Printed Certificate (must list Certificate Serial number and attach certificate to this form)

**** If this Account Source Code is selected, then select "N/A" from Generation Code field.*

Origin of Credits
State Rule Number from which the credits were originally issued (e.g. Reg XX, R1631, R2506, etc.)

Answer the following Questions:

A. Is this transaction part of a pooled transactions or market?

○ Yes → Attach Form 2007-3 to identify participants (Part A Only)

⊙ No → Go to Question B

B. Is seller an agent, broker, or other intermediary representing the owner of RTC ?

○ Yes → Attach Form 2007-3 to identify Owner of RTC (Part B Only)

⊙ No → Complete this form only

Date when this transaction was agreed upon (trading transaction date): 6/10/2014 → Attach purchase agreement or transaction confirmation

I certify that I am authorized to make this submission on behalf of the affected registered holders of the RTCs listed herein. I certify that the statements are true, accurate, and complete to the best of my knowledge.

Francisco Escobedo
Authorized Representative of Buyer/Transferee *(Print Name)*

Francisco Escobedo
Signature — Date: 6/10/2014

Francisco Escobedo
Authorized Representative of Seller/Transferor *(Print Name)*

Francisco Escobedo
Signature — Date: 6/10/2014

GE
Energy

Francisco Escobedo
Director, Asset Management

Inland Empire Energy Center
26226 Antelope Road
Menifee, CA 92585
USA

T 951 928 5941
Frank.Escobedo@ge.com

July 21, 2013

Ref. No. GE/IEEC – 0787

Reclaim Administration – RTC Transfer
South Coast Air Quality Management District
21865 Copley Dr.
Diamond Bar, CA 91765-0830

SUBJECT: INLAND EMPIRE ENERGY CENTER (IEEC) – 2013 RTC TRANSFER FROM GE ACCT #700126 TO IEEC ACCT #129816

To Whom It May Concern:

Attached is our completed form 2007-2 for the transfer of internal RTC's from the General Electric account #700126 to the Inland Empire Energy Center account #129816. This internal transfer is for the following single year trades:

- 23,380 lbs of Cycle 1, Coastal zone, RTC's Expiring December 31, 2013 at $0.00/lb/year
- 12,340 lbs of Cycle 2, Coastal zone, RTC's Expiring June 30, 2014 at $0.00/lb/year
- 96,380 lbs of Cycle 1, Coastal zone, RTC's Expiring December 31, 2014 at $0.00/lb/year
- 11,400 lbs of Cycle 1, Inland zone, RTC's Expiring December 31, 2014 at $0.00/lb/year
- 82,923 lbs of Cycle 2, Inland zone, RTC's Expiring June 30, 2014 at $0.00/lb/year

Since this is an internal transfer, the price is not applicable and there is no purchase agreement or transaction confirmation required.

If you have any questions or need further information, please don't hesitate to contact me at (951) 928-5941.

Sincerely,

Francisco Escobedo

Francisco Escobedo
Director, Asset Management

Enclosure

cc: Christine Stora - CEC

South Coast Air Quality Management District

Form 2007-2

Regional Clean Air Incentives Market Trading Credits (RTCs) Transaction Registration

Submit this form and required documents with Transaction Registration Fee pursuant to Rule 301

Mail To:
SCAQMD, RECLAIM Administration - RTC Transfers
P.O. Box 4830
Diamond Bar, CA 91765-0830

Tel: (909) 396-3119
www.aqmd.gov

Name of Buyer/Transferee: Inland Empire Energy Center, LLC — Account I.D. #: 129816

Name of Seller/Transferor: General Electric Company — Account I.D. #: 700126

Pollutant: ◉ NOx or ○ SOx *(Identify one pollutant only)* — Is this part of a Swap transaction? ○ Yes ◉ No

Is this form reporting the trade of an Infinite-Year-Block of RTCs? ◉ No ○ Yes

If "Yes," Total Value of Transaction $ N/A ; Enter N/A in the "Price" column below; Report in this form only those RTCs that are traded as part of a single negotiated price. File separate forms to transfer any other RTCs that were negotiated for a separate price.

(Attach a separate form if more than 8 transfers are being registered)

Terms of RTC Transferred: Cycle	From Compliance Year*	To Compliance Year*	Original Zone (Coastal or Inland)	Quantity (Pounds/year)	Price* ($/Pound)	Use Code (Buyer)	Generation Code (Seller)	Account Source Code (Seller)	Origin of Credits (Seller)	Certificate Serial Number (Seller)
1	12/31/2013	Single Year Trade	Coastal	23380	N/A	01	N/A	B	REGXX	N/A
2	6/30/2014	Single Year Trade	Coastal	12340	N/A	01	N/A	B	REGXX	N/A
2	6/30/2014	Single Year Trade	Inland	82923	N/A	01	N/A	B	REGXX	N/A
1	12/31/2014	Single Year Trade	Coastal	96380	N/A	01	N/A	B	REGXX	N/A
1	12/31/2014	Single Year Trade	Inland	11400	N/A	01	N/A	B	REGXX	N/A

* In the "From Compliance Year" Column, fill in the expiration date of the first compliance year RTCs. The "To Compliance Year" Column is used to enter (1) single year transaction, (2) perpetual stream transaction, or (3) multiple year transaction of RTCs of same zone, quantity, and price in a single line. For a single year transaction, mark this column "Single Year Trade". For a perpetual stream transaction, mark this column "All Years After". For a multiple year transaction, fill in the expiration date of the last compliance year. Use separate lines for transactions of different RTCs, quantities or prices. Transactions for all inclusive years between these two columns will be registered. **See reverse side for examples.**

Buyer Use Codes *(only one code per transaction)*

- 01 Increase RTC Allocation account balance to satisfy annual compliance
- 02 Use under Rule 2005 - New Source Review for RECLAIM
- 03 Increase RTC certificate account balance without issuance of physical certificate.
- 04 Increase RTC certificate account balance with issuance of physical certificate
- 05 Retire RTCs from market without issuance of physical certificate
- 06 Retire RTCs from market with issuance of physical certificate
- 07 Facility Acquisition (Change of Ownership)

NOTE: RTCs in Certificate or Printed Certificate Account must be transferred to Allocation Account to be eligible for compliance use.

Seller Generation Codes

- 01** Process Change
- 02** Addition of Control Equipment
- 03** Production Decrease
- 04** Equipment or Facility Shutdown
- 06 Facility Acquisition (Change of Ownership)
- 07 RTCs for Future Compliance Year, cause of generation not yet been determined

***** Selection of this Generation Code must be accompanied by the selection of Account Source Code "A" - Allocation Account.***

Seller Account Source Code *(only one code per transaction)*

- A Allocation Account
- B*** Certificate Account
- C*** Printed Certificate (must list Certificate Serial number and attach certificate to this form)

**** If this Account Source Code is selected, then select "N/A" from Generation Code field.*

Origin of Credits
State Rule Number from which the credits were originally issued (e.g. Reg XX, R1631, R2506, etc.)

Answer the following Questions:

A. Is this transaction part of a pooled transactions or market?

○ Yes → Attach Form 2007-3 to identify participants (Part A Only)

◉ No → Go to Question B

B. Is seller an agent, broker, or other intermediary representing the owner of RTC ?

○ Yes → Attach Form 2007-3 to identify Owner of RTC (Part B Only)

◉ No → Complete this form only

Date when this transaction was agreed upon (trading transaction date): 6/19/2013 → Attach purchase agreement or transaction confirmation

I certify that I am authorized to make this submission on behalf of the affected registered holders of the RTCs listed herein. I certify that the statements are true, accurate, and complete to the best of my knowledge.

Authorized Representative of Buyer/Transferee *(Print Name)*		Authorized Representative of Seller/Transferor *(Print Name)*	
Francisco Escobedo		Francisco Escobedo	
Signature: Francisco Escobedo	Date: 6/19/2013	Signature: Francisco Escobedo	Date: 6/19/2013

Inland Empire Energy Center, LLC
26226 Antelope Rd
Romoland CA 92585

000000001 0000010840 1 1 0684 042 7226

South Coast Air Quality Management
21865 E. Copley Drive
Diamond Bar CA 91765

INVOICE NUMBER	INVOICE AMOUNT	DESCRIPTION
rtc fee 2013	142.17	

CHECK NUMBER	VENDOR NUMBER	DATE	VENDOR NAME	TOTAL AMOUNT
10840	237495101	06/19/13	South Coast Air Quality Management	$142.17

CK0684 v.0.04 09-25-03

ORIGINAL DOCUMENT IS PRINTED ON CHEMICAL REACTIVE PAPER WITH MICROPRINTED BORDER - DO NOT CASH IF THE WORD VOID IS VISIBLE.

VOID VOID VOID

Inland Empire Energy Center, LLC
26226 Antelope Rd
Romoland CA 92585

00000
CHECK NO.

64-1278
611

DATE OF CHECK
06/19/13

PAY: **ONE HUNDRED FORTY TWO AND 17/100 DOLLARS**

TO THE ORDER OF SOUTH COAST AIR QUALITY MANAGEMENT
21865 E. COPLEY DRIVE
DIAMOND BAR CA 91765

CHECK AMOUNT
$142.17

Inland Empire Energy Center, LLC
Authorized Signature

Bank of America, N.A.
Atlanta, Dekalb County, GA.

DOCUMENT CONTAINS A TRUE WATERMARK. DO NOT CASH IF THE WATERMARK IS NOT VISIBLE. SEE REVERSE SIDE FOR COMPLETE SECURITY FEATURES.

⑈00000

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

AQMD

BUYER
ID: 129816

RTC Transfer Confirmation

SCAQMD RECLAIM ADMINISTRATION
P.O. BOX 4830, DIAMOND BAR CA 91765-0830

This letter is to confirm that the South Coast Air Quality Management District (AQMD) has received RTC trading information to comply with Rule 2007-Trading Requirements. The following summarizes your company information and the registration information that you and your trading partner specified in Form 2007-2. The transactions have been recorded and the RTC Listing was updated.

Registration No: 12059

Recording Date: 6/26/13
Pollutant: NOX

	TRANSFER FROM:	**TRANSFER TO:**
Company Name:	GENERAL ELECTRIC COMPANY	INLAND EMPIRE ENERGY CENTER, LLC
Facility ID:	700126	129816
Signing Representative:	Francisco Escobedo	Francisco Escobedo
Mailing Address:	1 RIVER RD SCHENECTADY, NY 12345-	26226 ANTELOPE ROAD MENIFEE, CA 92585-

Terms of RTC Transferred			Original Zone	Quantity (lb/yr)	Unit Price ($/lb)	Use Code	Generation Code	Account Source	Origin of Credits
Cycle	From Compliance Year (*)	To Compliance Year (*)							
1	12/31/2014	Single Year Trade	COASTAL	96,380	0.0000	01	NA	B	REGXX
2	6/30/2014	Single Year Trade	COASTAL	12,340	0.0000	01	NA	B	REGXX
1	12/31/2013	Single Year Trade	COASTAL	23,380	0.0000	01	NA	B	REGXX
1	12/31/2014	Single Year Trade	INLAND	11,400	0.0000	01	NA	B	REGXX
2	6/30/2014	Single Year Trade	INLAND	82,923	0.0000	01	NA	B	REGXX

(*) RTC Expiration Date

Approved By: Jill Whynot

(Signature) JILL WHYNOT
ASSISTANT DEPUTY EXECUTIVE OFFICER
Engineering & Compliance

Code Description :
Use Code (01) : Increase RTC Allocation account balance to satisfy annual compliance
Generation Code (NA) : Not Applicable
Account Source (B) : Certificate

COMMUNITIES FOR A BETTER ENVIRONMENT
EARTHJUSTCE
NATURAL RESOURCES DEFENSE COUNCIL
SIERRA CLUB

July 8, 2015

Philip Fine
Joe Cassmasi
South Coast Air Quality Management District
21865 Copley Dr.
Diamond Bar, CA 91765
pfine@aqmd.gov
jcassmassi@aqmd.gov

Re: Amendments to Regulation XX – NOx RECLAIM

Dear Dr. Fine and Mr. Cassmassi:

On behalf of Communities for a Better Environment, Earthjustice, Natural Resources Defense Council and Sierra Club ("Health Advocates"), we submit these comments on amendments to Regulation XX, which is slated to go to the Governing Board this fall. We are filing these comments based on the presentation that was provided at June 4, 2015 Working Groups Meeting (hereinafter "Staff Presentation"). At the outset, we remind the South Coast Air Quality Management District ("District") of the urgent ozone and particulate matter problems facing the region. Reducing pollution from the sources in the NOx Regional Clean Air Incentives Market ("RECLAIM") program is essential to achieving our air quality goals and attaining ozone and particulate matter standards. The following sections outline our positions on various issues raised at the last Working Group meeting.

I. The Cap Shave for the Program Should be a Minimum of 14.85 Tons Per Day ("tpd"), Not 14 tpd.

We do not agree with the decision to reduce the total shave amount by .85 tpd, from the required 14.85 tpd to 14 tpd. California's Health & Safety Code is abundantly clear that trading programs must "result in an equivalent or greater reduction in emissions at equivalent or less cost compared with current command and control regulations. . . ." Cal. Health & Safety Code § 39616. In reviewing the materials produced through this rulemaking, the Best Available Retrofit Control ("BARCT") assessments show that a BARCT-equivalent program would result in 14.85

tpd fewer emissions. Accordingly, to comply with Health & Safety Code section 39616, the shave for the RECLAIM program must also be at least 14.85 tpd. We also suggest shaving even more from the program given the large size of the "black box" that must be reduced to meet ozone standards.

II. The Implementation Schedule is Weak.

We are deeply concerned that the schedule for implementation for the shave is too protracted. *See* Slide 4 of the Staff Presentation. Given recent difficulties in meeting various air quality standards, including the 1997 and 2006 standards for fine particle pollution ("PM2.5"), it would be prudent to move up some of the latter year reductions. In fact, we suggest amending the schedule to the following to ensure reductions on the front end in time for compliance with standards.

Year	Current Proposal	Health Advocates Proposal
2016	4 tpd	5 tpd
2018	2 tpd	3 tpd
2019	2 tpd	3 tpd
2020	2 tpd	2 tpd
2021	2 tpd	1.85 tpd
2022	2 tpd	0 tpd

We believe our proposed schedule represents an approach more in line with the directive of the California Health & Safety Code than the implementation schedule proposed in Slide 4 of the Staff Presentation.

III. The District Should Not Establish a New Source Review ("NSR") Set Aside.

Health Advocates do not support the implementation of a District-operated set-aside for New Source Review ("NSR") holdings. There is no basis for the District to undertake this task. In fact, this provision exists to ensure the program does not erode air quality progress in the region. We think this is a necessary safeguard, and we have not heard a compelling reason why the District should take on this duty. Industries have complied with this provision for decades, and it makes sense to continue to place this duty on industry.

IV. The California Environmental Quality Act Analysis Should Examine a Command and Control Alternative.

It is important that the Governing Board and the public receive full information on the environmental landscape of this action. In particular, through the California Environmental Quality Act ("CEQA") process, an assessment of a Command and Control alternative will be important to understand how quickly desperately needed reductions could be implemented in the

South Coast under a regulatory program requiring implementation of readily available technologies, many of which have not been installed at the largest NOx emitters in the South Coast. Under the currently proposed approach, clean up would be protracted for many years as the shave is implemented. A Command and Control Alternative would achieve reductions sooner than this compliance schedule.

V. Industry's Critique on Credit Prices Carries No Water.

At the workshop, representatives for NOx emitters suggested that environmental interests were naïve in solely looking at the prices of short term credits in asserting that NOx RECLAIM credits are priced too low. They claimed that environmental interests failed to look at the price of Infinite Year Block ("IYB") credits. Rather than rebut the claims environmentalists have made that the NOx RECLAIM system is broken because credits prices are too low, the IYB credits only help boost the environmentalists claim. Even with the recent doubling of IYB NOx credits in 2014, the value of IYB credits has been excessively low for over a decade. The following chart from the March 5, 2015 Annual NOx RECLAIM report reprinted below confirms this:

Table 2-5
IYB NOx Pricing (Excluding Swaps)

Calendar Year	Total Reported Value ($ millions)	IYB RTC Traded with Price (tons)	Number of IYB Registrations With Price	Average Price ($/ton)
1994*	$1.3	85.7	1	$15,623
1995*	$0.0	0	0	N/A
1996*	$0.0	0	0	N/A
1997*	$7.9	404.6	9	$19,602
1998*	$34.1	1,447.6	23	$23,534
1999*	$18.6	438.3	19	$42,437
2000*	$9.1	184.2	15	$49,340
2001*	$34.2	416.9	25	$82,013
2002	$5.5	109.5	31	$50,686
2003	$14.3	388.3	28	$36,797
2004	$12.5	557.0	52	$22,481
2005	$43.1	565.3	71	$76,197
2006	$65.2	432.9	50	$150,665
2007	$45.4	233.5	25	$194,369
2008	$49.7	245.6	27	$202,402
2009	$16.7	134.2	14	$124,576
2010	$14.3	149.0	13	$95,761
2011	$9.1	160.7	29	$56,708
2012	$2.2	46.6	13	$48,146

2013	$12.0	260.9	17	$45,914
2014	$99.7	902.2	49	$110,509

District, Staff Report, 2-24, March 6, 2015, *available at* http://www.aqmd.gov/docs/default-source/Agendas/Governing-Board/2015/2015-mar6-029.pdf?sfvrsn=2.

The claims of industry lobbyists that the IYB credits are appropriately priced are not true. In fact, like the short term credits, these credits are exceptionally low. Even with a more than doubling of the IYB prices in 2014 compared to 2013, these credits are only 18% of the $609,187 cost established by the District pursuant to section 39616(f) of the California Health & Safety Code, which is set to ensure credit prices do not go too high. That the failure of these IYB credits to even approach 1/5 of the District's ceiling for credit costs just bolsters the excessive number of credits in the NOx RECLAIM system. Overall, the evidence conclusively suggests that the credits are not priced correctly to push for pollution reductions at a level commensurate with what command and control would achieve, which is borne out in the District's BARCT assessments.

VI. The Shave Approach Must Ensure Reductions from Refineries and Powerplants.

The evidence presented by the District in this rulemaking indicates that refineries have used the NOx RECLAIM system as a shield from actually installing pollution control equipment like Selective Catalytic Reduction ("SCR"). Given this past behavior, we suggest that the best path forward is that refineries be taken out of the NOx RECLAIM program and be required to install pollution control equipment.

If this cannot happen, we support the shave approach number 4 on slide 2 of the Staff Presentation, which focuses on large emitters like refineries and natural gas powerplants. Absent removing those facilities unwilling to install pollution controls, this methodology appears to be the most sound approach to allocating the shave of those presented at the June 4, 2015 working group meeting.

Overall, we are deeply committed to ensuring stationary sources clean up harmful NOx emissions in the South Coast. As it stands now, the NOx RECLAIM program has failed to spur adoption of available pollution technologies for many large facilities, and has accordingly failed to adequately reduce NOx emissions. In addition, it has continued to allow high NOx emissions in the disproportionately impacted neighborhoods near refineries and powerplants, raising substantial environmental justice issues. Thus it has dramatically displayed one of the major flaws of a trading system.

We therefore support efforts to retool the program, but urge SCAQMD to do so in a way that meets the urgent need of South Coast residents for clean air and clean energy.

Please do not hesitate to contact us if you have questions.

Sincerely,

Adrian Martinez
Elizabeth Forsyth
Earthjustice

Bahram Fazeli
Communities for a Better Environment

David Pettit
Natural Resources Defense Council

Evan Gillespie
Sierra Club

From: Arnie.Smith@Fluor.com
Sent: Tuesday, August 11, 2015 2:16 PM
To: Kevin Orellana
Subject: Re: **SAVE THE DATE** SCAQMD NOx RECLAIM Working Group Meeting
Attachments: AACE_CLASSIFICATION_SYSTEM.pdf

Hi Kevin -

I wanted to share with you this document produced by the Association for the Advancement of Cost Estimating (AACE):

This document highlights the deliverables generated in a gated/phased project development and the corresponding estimate detail and accuracy expected. This is followed by **all** major refining and chemical companies when appraising, selecting, and defining projects for internal funding or external financing. **All** of the major EPCs follow process this as well. Fluor and many other EPCs - and the operating companies - have developed proprietary design manuals that address gated process development and we all follow these very rigorously.

So how does this apply to a NOx RECLAIM Program?

For each potential project, a screening level study estimate (Class 5) is developed for each possible solution for a heater's NOx emissions, for example. Screening whether (1) newer/better burners would be a good choice for NOx mitigation, whether (2) improving the refinery fuel gas for lower NOx generation due to heavy hydrocarbon removal or hydrogen removal, whether (3) improved SCR catalysts would be effective, whether (4) new and/or larger SCR systems are required, or whether (5) the heater should be replaced altogether.

The same would apply to FCC regenerator emissions, but from a slightly smaller list of technical choices.

A variation would apply to sulfur plant incinerators with the caveat that the mitigation system cannot interfere with H_2S destruction during an emergency release.

Following a positive outcome of the screening level study, a more detailed look is undertaken to better define the scope and improve the cost estimate. This estimate is usually an equipment factored or Class 4 estimate.

Following a positive outcome of the more detailed study, the refiner would receive internal funding for a Front End Engineering Design effort, which is of sufficient detail and completeness that external financing could be sought or an internal AFE is pursued. The decision to proceed following a FEED effort is serious since it will involve equipment and construction commodity purchased.

With external financing or an internal AFE, the project can now proceed into the detailed design, procurement, and construction effort.

All this takes time:

- Studies take from weeks to several months to complete, depending on the scope of the problem.
- FEEDs tend to take 6 to 12 months, depending on the project complexity and the impacts to offsites and utility systems.
- EPC is usually 18 to 30 months when new equipment is involved and will depend greatly on the project complexity and its impacts on other systems in the refinery.

In between each of the steps is a review and approval period by the client - likely 1 to 3 months, depending on project complexity and the financial analysis required to move forward.

This disciplined decision making approach is driven by refining being a "commodity" business and one that is extremely capital intensive. Shortcuts do not save time or money. An incomplete technology assessment or rushed project development can lead to regretful choices and inadequate mitigation.

At this point, we are probably one to two months away from having finalized NOx RECLAIM rules. Then, we are only another two months from the beginning of the first compliance year. There will be inadequate time for project development with any results in 2016/2017 - even for simpler scopes like burner replacements in existing heaters or catalyst upgrades in existing SCRs. But, new scrubbers or new SCRs would not be able to provide any mitigation benefit until 2018/2019.

The ongoing SOx RECLAIM Program had a gap of 26 months from the end of rule-making to the beginning of compliance - which would allow for some mitigation to be realized in the first compliance year. A three year gap would have insured an even stronger result.

A three year gap between rule-making and the first compliance year for NOx RECLAIM would have provided a better start for a real NOx reduction.

I am available anytime if you wish to discuss this further.

Thanks and best regards -

Arnie

Arnie Smith | **Fluor** | Executive Director, Process Technology | 3 Polaris Way, Aliso Viejo, CA 92698 | Office: +1 949.349.2231 Mobile: +1 949.322.6985 |
Arnie.Smith@Fluor.com

From: Karl Lany <klany@montrose-env.com>
Sent: Thursday, August 20, 2015 10:58 PM
To: Joe Cassmassi
Cc: Kevin Orellana; Jill Whynot; Gary Quinn
Subject: PAR 2002 RECLAIM and Rule 1146.2 Boilers (Rule 219 exempt)
Attachments: Karl Lany.vcf

Thanks for taking the steps you have to accommodate Rule 219 boiler technology into the proposed RECLAIM amendments. After giving the concept more consideration, I continue to question the proposed requirement that such boilers be subject to testing requirements in order to qualify for RECLAIM reporting factors that reflects certification standards.

Several people at yesterday's meeting raised concerns about the need for, and practicality of, such tests (cost, the presence of certification data, and the way in which certification data supports SIP credit). SCAQMD's position is that certification is for a family of boilers or boiler models, rather than each individual boiler. I understand that concept because of my experience with diesel engine certification programs. There are many parallels that I expect to exist and those parallels lead one to shy away from a testing requirement.

Even though boilers may be certified in groupings, if the boiler program is anything at all like the engine certification program, those groupings are based upon similarity of the equipment, combustion technology and the reasonable expectation that the environmental performance of the lead device truly reflects the environmental performance of the entire family of devices. It seems to me that groups of boilers being certified have very few technological variables. In fact, Rule 1146.2 requires certification based upon each boiler model, which appears to be more restrictive than the engine certification program which includes many different engine ratings and applications in a single family.

As we debate the need for small boiler testing, we should pay close attention to the equity of SCAQMD policy, relative to other certified equipment such as diesel emergency engines that are brought into the RECLAIM program. I recognize I am comparing process units that go through district permitting with Rule 219 permit exempt units, but the comparison is valid because the technology analysis performed by SCAQMD when permitting diesel emergency engines is rather simple.

SCAQMD makes all NSR determinations, including BACT and offset, for certified emergency engines based upon engine certification standards unless the applicant proposes unit-specific certified rates or manufacturer data. SCAQMD does not question the legitimacy of EPA or CARB's certification. Instead SCAQMD makes a very basic determination of the engine certification status and the emission rates to which the engine is certified. SCAQMD then uses the certification status to determine NSR compliance. Then, because Rule 2002 allows, SCAQMD uses the certification standard to determine a RFECLAIM process unit emission factor. The entire SCAQMD program for certified diesel engines rests upon certification standards and excludes any emissions testing. It makes sense that the benefits of certification (exclusion from unnecessary emissions tests) that are extended to process unit diesel engines in RECLAIM would also be extended permit exempt natural gas boilers that arte subjected to a similar certification program.

I sincerely hope that SCAQMD reconsiders its proposed testing requirements for Rule 219 boilers in RECLAIM and instead provides a more practical solution that reflects the legitimacy of its boiler certification program I'm always happy to discuss further at your convenience.

Thanks.

Karl A. Lany
Senior Vice President
Regulatory Compliance Services
SCEC Air Quality Specialists
an affiliate of Montrose Environmental Group, Inc.
1631 St. Andrew Place, Santa Ana, CA 92705
T: 714.282.8240 | M: 714.376.6531
klany@montrose-env.com
www.montrose-env.com

From: Piantka, George [mailto:George.Piantka@nrg.com]
Sent: Friday, August 14, 2015 4:55 PM
To: Jill Whynot; Joe Cassmassi
Subject: RE: RECLAIM Rulemaking Follow up

Hello Jill and Joe,

I appreciate the time you spent with me last month. I am unclear whether I will be able to make the August 19 RECLAIM Working Group meeting, but nonetheless, we continue to be engaged with the developments of the rulemaking/shave. I have a couple points to consider. I am not considering this formal written comments; just some follow up thoughts. I can give you a call or we can discuss at the August 19 meeting if I can make it.

1. In Rule 2005, will there be proposed language to address annual holding limit requirements for a facility like Walnut Creek. I did not see it, unless I missed it.
2. During our meeting, I may have understated the financial impact to a new facility like Walnut Creek that is different than an existing RECLAIM facility or new plant at an existing RECLAIM facility. In satisfying NSR (unlike a legacy RECLAIM facility), we purchased IYB Cycle 1 and 2 RTCs from the market. Demonstration that we satisfied the RTCs for annual NOx PTE was not only necessary for the Permit to Construct and annual Permit to Operate but also for the financing of the WCEP. We would now represent that the asset has lost the equivalent of 47% of its NOx IYB RTCs at the current rate of say $115/lb-yr and address the means to which we can demonstrate our continued holding and/or access to these RTC for the lenders. While not obvious, the financial implications are different than a facility that has relied on an existing RECLAIM account or the ability to reconcile its emissions for the respective year. It is the difference between losing the unrealized value of IYB RTCs in a legacy RECLAIM account versus the purchase, shave and possible replacement of them at the new market condition (or from the Adjustment Account?) to meet its PTE. This is one of the reasons why we believe WCEP should be exempt from the shave. More food for thought.
3. Any concern about challenges to removal of the annual holding limit requirement by the environmental community?

Thanks for the time. And we can discuss these thoughts soon.

Best Regards,

George Piantka, PE

Sr. Director, Regulatory Environmental Services
NRG Energy, Inc.
5790 Fleet Street, Suite 200
Carlsbad, CA 92008
760.710.2156 office
760.707.6833 mobile
george.piantka@nrg.com

From: Jill Whynot [mailto:JWhynot@aqmd.gov]
Sent: Monday, July 20, 2015 10:28 AM
To: Piantka, George
Cc: Joe Cassmassi
Subject: Re: RECLAIM Rulemaking Follow up

George
kid and I can meet at 8:30 tomorrow morning if that would work for you. Call my number and we can let you know what meeting room.
Jill

Sent from my iPhone

On Jul 19, 2015, at 6:47 PM, Piantka, George <George.Piantka@nrg.com> wrote:

> Hello Jill,
>
> Thanks for discussing the proposed RTC shave and more specifically the Walnut Creek Energy Park site – we have annual holding requirements for new equipment (5 LMS 100 gas turbines) that are BACT. Will you have an opportunity to discuss further on Tuesday July 21. I could come in to the District in the morning, before I have to leave for Santa Barbara for a late afternoon meeting. I will unfortunately miss the July 22 workshop meeting, but will have someone monitor the meeting on NRG's behalf.
>
> George Piantka, PE
> Director, Regulatory Environmental Services
> NRG Energy, Inc.
> 5790 Fleet Street, Suite 200
> Carlsbad, CA 92008
> 760.710.2156 office
> 760.707.6833 mobile
> george.piantka@nrg.com

From: Casey, Chuck <CCasey@riversideca.gov>
Sent: Thursday, September 24, 2015 1:20 PM
To: Kevin Orellana
Cc: Karl Lany; Perez, James M.; Joel Lepoutre; Feragen, Wayne; Manny Robledo; Marnie Dorsz (mdorsz@montrose-env.com); Wright, Jeffrey
Subject: bases for inclusion on Top 90% of RTC Holder list
Attachments: WHEELABRATOR NORWALK ENERGY CO INC 51620.pdf; ALTAGAS POMONA ENERGY INC 176708.pdf; CARSON COGENERATION COMPANY 118406.pdf; CORONA ENERGY PARTNERS, LTD 68042.pdf; HARBOR COGENERATION CO, LLC 156741.pdf; NP COGEN INC 112853.pdf; OLS ENERGY-CHINO 47781.pdf; RegXX Nox shave list July 2015.pdf; SO CAL EDISON CO 4477.pdf; THUMS LONG BEACH 800330.pdf

Kevin,
On behalf of the City of Riverside, City of Anaheim and City of Colton, thank you for your time yesterday regarding an audit of the Preliminary Draft Report – NOx RECLAIM July 21, 2015 Table U.1 "*List of 65 Affected Facilities and Investors.*" The draft report states "*Additionally, all power plants would be included in this option*." (pg 210) but in fact all power plants are NOT included on table U.1.

Attached are the Facilities' "NOx Information" sheets from the AQMD website which appear to hold RTCs and are "power plants" therefore it's a assumed, as per your draft report, would be included on the list but in fact are not. The attachments include power plants such Corona Energy Partners, Wheelabrator Norwalk Energy Co, OLS Energy – CHINO, Carson Cogeneration Company, NP Cogen Inc, Thumbs Long Beach, Harbor Cogeneration Co, and Altagas Pomona Energy inc.

You and I covered a wide range of thoughts yesterday including; ALL power plants are on the list, cogeneration facilities are excluded from the list, "new" power plants are on the list, companies without NSR requirements are excluded, and power plants without any RTCs are not on the list. But in each of these cases I showed how your list contradicts the statement.

For example, you said the list may not include cogeneration facilities even though one of my facilities (facility ID 164204) is on the list and is a cogeneration. Additionally, your familiar with the inclusion of power plants (facility ID 132191 and 132192 for example) with zero RTCs who are on the U.1 list.

In summary, the list as provided in table U.1 needs to be audited with a full explanation of who is included or excluded and the reason for each. The NOx shave percentage adjusted for non-refinery RTC holders' weighted reduction, currently 47%, would require adjustment if the list changes.

Thank you. Please let me know if you have any questions,

Chuck Casey
Utility Generation Manager
Riverside Public Utilities
5901 Payton Ave
Riverside, CA 92504
951.710.5010 direct
909.376.9069 cell
951.710.5040 fax
ccasey@riversideca.gov