BOARD MEETING DATE: December 4, 2015 AGENDA NO. 31

PROPOSAL: Amend Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines

SYNOPSIS: SCAQMD staff has met with several biogas engine operators that have committed to installing control equipment for biogas engines. However, some installations will take longer than expected and will reach full compliance after the current deadline of January 1, 2016. Additionally, U.S. EPA has raised concerns regarding the approvability of Rule 1110.2 into the State Implementation Plan because the current breakdown provisions in the rule allow unlimited emissions during breakdowns that are not subject to any enforcement action if they are reported. The proposed amendments would extend the compliance date for all biogas engines, provide a compliance option for additional time with the payment of a compliance flexibility fee, and address U.S. EPA's concerns on equipment breakdowns and potential excess emissions without enforcement by establishing a limit for exceedances due to breakdowns without enforcement action per calendar quarter. Based on stakeholder comments, alternative language is proposed that would remove current rule language stating that certain breakdowns are not violations of the rule and adding suggested U.S. EPA language making clear that breakdowns may be subject to federal enforcement, thus satisfying U.S. EPA concerns.

COMMITTEE: Stationary Source, June 21, 2013, June 20, 2014, January 21, 2015, and September 18, 2015, Reviewed.

RECOMMENDED ACTIONS:
Adopt the attached resolution:
1. Certifying the Final Subsequent Environmental Assessment; and
2. Amending Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines.

Barry R. Wallerstein, D.Env.
Executive Officer

PM:JW:JC:GQ:KO

Background

Rule 1110.2 regulates oxides of nitrogen (NOx), carbon monoxide (CO), and volatile organic compound (VOC) emissions from liquid and gas fueled internal combustion engines operating in the SCAQMD producing more than 50 rated brake horsepower (bhp). The rule was adopted in 1990 and last amended in 2012 to establish an effective date of January 1, 2016 for owners and operators of biogas engines to meet the emission limits that all other engines under this rule were required to meet in July 1, 2011. A Final Technology Assessment was also completed which outlined several technologies for biogas engine emission control along with costs.

Since the amendments to Rule 1110.2 on September 7, 2012, SCAQMD staff has met with the stakeholders periodically, both in public forums and through individual meetings for updates on technology implementation. Based on feedback from these operators, some installations will take longer to install than expected and will reach full compliance after the current deadline of January 1, 2016. The projected range of implementation dates varies from mid-2016 to mid-2018. Based on the feedback from the regulated facility operators, SCAQMD staff is proposing to extend the compliance deadline for biogas engines beyond January 1, 2016, to accommodate control equipment procurement and installation.

In addition U.S. EPA Region IX staff has raised SIP approvability issues with current Rule 1110.2 language, which provides that sources are not considered in violation if any breakdowns are properly reported and corrected, thus potentially allowing gross emissions during preventable breakdowns. Under this assessment, the current rule language is not consistent with national policy as described in U.S. EPA's recent supplemental notice of proposed rulemaking on excess emissions from startup, shutdown, and malfunction (SSM). This action was finalized on June 12, 2015. The inconsistent Rule 1110.2 language originated in the February 2, 2008 adopted amendment and U.S. EPA Region IX's comments refer to this language in the July 9, 2010 amendment. The inconsistency of the rule language with U.S. EPA national policy and its final action precludes its ability to fully approve the rule. Amendments are proposed to Rule 1110.2 to resolve U.S. EPA's issue with potential gross emission violations during breakdowns. Failure to resolve this issue will result in U.S. EPA's disapproval of the 2010 or currently proposed amendments into the State Implementation Plan (SIP). If this disapproval is finalized, sanctions would be imposed unless the U.S. EPA approves subsequent SIP revisions that correct the rule deficiencies within 18 months of disapproval.

Public Process

Since the amendments in 2012, the Biogas Technology Advisory Committee has met on October 29, 2013, May 28, 2014, October 29, 2014, January 14, 2015, and February 19, 2015.

The Stationary Source Committee was presented with updates on the implementation of the rule and demonstration projects as directed by the adopting resolution for the 2012 amendment, which required updates to the Stationary Source Committee at least yearly after the 2012 amendments. The Committee heard updates on Rule 1110.2 on June 21, 2013, June 20, 2014, January 21, 2015, and September 18, 2015.

A task force meeting was held on April 23, 2015 to introduce the proposed amendments and a working group meeting was held on July 9, 2015 where SCAQMD staff presented preliminary rule language for the proposed amendments. The public workshop was held on July 29, 2015 and three more working group meetings were held on August 18, 2015, September 15, 2015, and October 27, 2015.

Staff has also met individually with nearly every biogas facility operator to discuss site-specific issues, technologies, long-term plans for existing biogas engines, and costs. Several site visits have been conducted by SCAQMD staff at affected facilities.

Affected Facilities

Rule 1110.2 applies to all stationary and portable reciprocating internal combustion engines (ICEs) over 50 brake horsepower (bhp). PAR 1110.2 affects the subset that contains engines fueled with biogas, which are those that are operated at landfills and wastewater treatment plants. There are currently 58 biogas engines operating in the Basin. Of these engines, 27 are digester gas-fueled and 28 are landfill gas-fueled. These engines are operated by 13 independent operators at 22 locations.

For the proposed amendments pertaining to U.S. EPA's concerns over equipment breakdowns and excess emissions, these requirements would apply to all operators of gaseous- and liquid-fueled engines governed by this rule.

Proposed Amendments

The key proposed amendments can be summarized as follows:

- Extend the effective date for compliance to January 1, 2017 for all biogas engines.
- Extend the effective date for compliance to January 1, 2018 for demonstration project biogas engine operators.
- Provide an alternate compliance option to provide operators additional time for engine retrofits beyond the proposed compliance date with the submittal of a compliance plan and payment of a compliance flexibility fee.
    - Up to January 1, 2019 for demonstration projects
    - Up to January 1, 2018 for all other biogas engines
- The compliance flexibility fee would be allowed to be paid in quarterly increments, up to one year beyond the applicable compliance date.

- To address U.S. EPA's concerns on breakdowns and potential excess emissions without enforcement, staff is proposing that within any calendar quarter, a facility operator would be allowed up to three incidences of breakdown per engine of NOx emissions that exceed 45 ppmv for lean burn engines and 150 ppmv for rich burn engines. For CO emissions, no more than three incidences of breakdown per quarter would be allowed that are above 250 ppmv for lean burn engines and 2000 for rich burn engines.
- For biogas engines operating until the compliance date for the limits specified in Table III-B, the emission thresholds for breakdowns that will count towards the incidence limit are 185 ppmv for NOx and 2000 ppmv for CO.
- An alternative rule proposal has been included that would remove rule language stating that breakdowns are not violations and add suggested U.S. EPA language making clear that breakdowns would subject operators to potential federal enforcement action or citizen lawsuits.
- Clarifications to Inspection and Monitoring requirements have been made which improve readability and enforcement.

Emission Reductions and Cost Effectiveness
The emission reductions calculated during the 2012 amendments were 0.9 tons per day of NOx, 0.5 tons per day of VOC, and 20.0 tons of CO. The reductions under the proposed amendment would occur in two steps. The first reductions will occur by January 1, 2017 and the second step of reductions will occur one to two years later when all biogas engines will comply with the rule limits, including those under the alternate compliance option.

In 2012, using the District model, the cost effectiveness was estimated to range from $1,700 to $3,500 per ton of NOx, VOC, and CO/7 reduced. Staff also calculated cost effectiveness to account for additional contingencies, based on stakeholder feedback. With the additional contingencies, the cost effectiveness ranged from $2,600 to $5,900 per ton. All of the cost effectiveness estimates are within the range of estimates considered by the Governing Board as part of past rulemakings.

Digester gas and landfill gas engines of all sizes were shown to be cost-effective in 2012. The proposed amendments pertaining to U.S. EPA's policy on excess emissions from breakdowns will not require the modification or addition of control equipment and will not have an effect on costs.

Key Issues

1. *The Need for Additional Time to Comply*. Most of the stakeholders notified SCAQMD staff that they would need more time beyond January 1, 2016. In particular, operators of biogas engine demonstration projects have encountered delays and operational issues that would also necessitate additional time to

resolve. One operator stated that they will need even more time to comply than is being proposed.

2. *Complying with EPA's Breakdown Provisions*. SCAQMD staff has received feedback from the regulated community that points to concerns with complying with both SCAQMD rules and U.S. EPA's SSM policy. Industry representatives have requested alternative rule language which would remove rule language stating that breakdowns are not violations, thus subjecting operators to potential federal enforcement action or citizen lawsuits. It is also important to note that this alternative rule language is more stringent than the quarterly breakdown limitation. Any future changes to this language might be considered backsliding and therefore, potentially not SIP-approvable.

AQMP and Legal Mandates

The California Health and Safety Code requires the SCAQMD to adopt an Air Quality Management Plan to meet state and federal ambient air quality standards and adopt rules and regulations that carry out the objectives of the AQMP. The proposed amendments of Rule 1110.2 will provide additional reductions that will aid in attaining more stringent federal ozone and particulate matter standards. Reductions in NOx will help in attaining the federal 24-hour $PM_{2.5}$ standard by 2019, while reductions in NOx and VOC will aid in attaining the ozone standard in 2024.

California Environmental Quality Act (CEQA) Analysis

PAR 1110.2 is considered a "project" as defined by the California Environmental Quality Act (CEQA), and the SCAQMD is the designated lead agency. Pursuant to CEQA and SCAQMD Rule 110, SCAQMD staff reviewed PAR 1110.2 and concluded that a Subsequent Environmental Assessment (SEA) was the appropriate CEQA document for the proposed project. Staff released a Notice of Preparation and Initial Study (NOP/IS) for a 30-day public review period from July 29, 2015 to August 27, 2015, and a CEQA scoping meeting was held on Thursday, August 13, 2015 at 10 AM in Conference Room GB at SCAQMD Headquarters. No comments were received on the NOP/IS or at the scoping meeting. The Draft SEA was circulated for public review and comment from September 1, 2015 to October 16, 2015. No comments were received on the Draft SEA. Since the close of the comment period, revisions have been proposed to PAR 1110.2. Staff has analyzed these proposed revisions and have determined that they do not trigger recirculation pursuant to CEQA Guidelines §15088.5.

Socioeconomic Analysis

PAR 1110.2 would delay implementation of new concentration limits for biogas-fired engines at affected facilities from 2016 to between 2017 and 2019. In addition, PAR 1110.2 would affect fewer biogas-fired engines. The additional time for compliance and fewer affected engines would result in potential savings for affected facilities. As such, no adverse socioeconomic impact is anticipated for PAR 1110.2.

Resource Impacts

Existing staff resources are adequate to implement the proposed amendments.

Attachments

A. Summary of Proposal
B. Rule Development Process
C. Key Contacts List
D. Key Issues
E. Resolution and Attachment 1 to the Resolution
F. Proposed Amended Rule
G. Alternative Rule Proposal
H. Staff Report
I. Subsequent Environmental Assessment for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines

ATTACHMENT A

SUMMARY OF PROPOSAL

Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines

Effective date for compliance
Extend the compliance date as follows:

- January 1, 2017 for all biogas engines. [subparagraph (d)(1)(C) – Table III-A]
- January 1, 2018 for demonstration project biogas engine operators. [subparagraph (d)(1)(F)]

Alternate compliance option [subdivision (h)]
These provisions would give operators additional time for engine retrofits beyond the proposed compliance date with the submittal of a compliance plan and payment of a compliance flexibility fee.

- Up to January 1, 2018 for all biogas engines
- Up to January 1, 2019 for demonstration projects

Compliance Flexibility Fee [paragraph (h)(2)]
The compliance flexibility fee would be allowed to be paid in quarterly increments, up to one year beyond the applicable compliance date.

Breakdowns – Option 1 [paragraph (c)(3) and clause (f)(1)(D)(iii)]
To address U.S. EPA's concerns on breakdowns and potential excess emissions without enforcement, staff is proposing that within any calendar quarter a facility operator would be allowed up to three incidences of breakdown per quarter of NOx emissions that exceed 45 ppmv for lean burn engines and 150 ppmv for rich burn engines. For CO emissions, no more than three incidences of breakdown per quarter would be allowed that are above 250 ppmv for lean burn engines and 2000 for rich burn engines.

For biogas engines operating until the compliance date for the limits specified in Table III-B, the emission thresholds for breakdowns that will count towards the incidence limit are 185 ppmv for NOx and 2000 ppmv for CO.

Breakdowns – Option 2 [paragraph (c)(3) and clause (f)(1)(D)(iii)]
An alternative rule proposal has been included that would remove rule language stating that breakdowns are not violations and adding suggested U.S. EPA language making clear that breakdowns would subject operators to potential federal enforcement action or citizen lawsuits.

Clarifications [subclause (f)(1)(A)(iii)(I), subparagraph (f)(1)(D), clause (f)(1)(F)(iii), clause (f)(1)(H)(iii), and Attachment I]
Clarifications to Inspection and Monitoring requirements have been made which improve readability and enforcement.

ATTACHMENT B

RULE DEVELOPMENT PROCESS

Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines

Initial Rule Development
October 2012

↓

- Five Biogas Technology Advisory Committee Meetings: October 29, 2013, May 28, 2014, October 29, 2014, January 14, 2015, and February 19, 2015
- One Task Force Meeting: April 23, 2015
- Four Working Group Meetings: July 9, 2015, August 18, 2015, September 15, 2015, and October 27, 2015
- CEQA Scoping Meeting – August 13, 2015
- Public Workshop: July 29, 2015
- Stationary Source Committee Meetings: June 21, 2013, June 24, 2014, January 21, 2015, and September 18, 2015.

There were also numerous meetings with various stakeholders during the entire rulemaking process.

↓

CEQA Draft SEA Released for
45-Day Review
Release Date: September 1, 2015

↓

Set Public Hearing: October 2, 2015

↓

Public Hearing: December 4, 2015

Thirty-six (36) months spent in rule development.

ATTACHMENT C

KEY CONTACTS LIST

Agency Representatives
Bay Area Air Quality Management District (BAAQMD)
California Air Resources Board (CARB)
California Association of Sanitation Agencies (CASA)
Orange County Waste and Recycling (OCWR)
Southern California Alliance of Publicly Owned Treatment Works (SCAP)
U. S. Environmental Protection Agency (EPA)

Affected Facilities
Brea Parent 2007, LLC
City of Riverside
City of San Bernardino Municipal Water Department
Eastern Municipal Water District (EMWD)
Fortistar
Inland Empire Utilities Agency (IEUA)
J&A Whittier
Los Angeles County Sanitation District (LACSD)
Montauk Energy
Orange County Sanitation District (OCSD)
Riverside County Waste Management Department
South Orange County Wastewater Authority (SOCWA)
Waste Management

Other Interested Parties
Applied Filter Technology
Environ Strategy Consultants, Inc.
ESC Corporation
Flex Energy
Fuel Cell Energy
Johnson Matthey
Miratech Corporation
NOxTech
Sierra Club
Southern California Edison
Southern California Gas Company
Representatives from other companies and other interested individuals

ATTACHMENT D

KEY ISSUES

Issue	Industry Comment	Staff Response
The Need for Additional Time to Comply	Most of the stakeholders notified SCAQMD staff that they would need more time beyond January 1, 2016. In particular, operators of biogas engine demonstration projects have encountered delays and operational issues that would also necessitate additional time to resolve. One operator stated that they will need even more time to comply than is being proposed.	The current proposal extends the compliance dates by one year with a provision to extend the compliance date an additional year by paying a fee on a quarterly basis. The Stakeholders have had sufficient time to comply with the proposed compliance date. The fees to extend the compliance date do not pose a significant financial hardship, especially since they can extend the date and pay the fee on a quarterly basis.
Complying with EPA's Breakdown Provisions	Concerns have been raised by the regulated community regarding compliance with both SCAQMD rules and U.S. EPA's Startup, Shutdown, and Malfunction (SSM) policy. Industry representatives have requested a delay in addressing this issue, or alternative rule language which would remove rule language stating that breakdowns are not violations.	Staff is proposing two options (1) Staff's proposal of limiting breakdowns to three per quarter, and (2) the regulated community's proposal of removing rule language stating that breakdowns are not violations, and adding suggested U.S. EPA language making clear that breakdowns would subject operators to potential federal enforcement action or citizen lawsuits. It is important to note that Option 2 is more stringent than Option 1. Any future changes to this language might be considered backsliding and therefore, potentially not SIP-approvable.

ATTACHMENT E

RESOLUTION NO. 2015 - __________

A Resolution of the South Coast Air Quality Management District (SCAQMD) Governing Board certifying the Final Subsequent Environmental Assessment for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines.

A Resolution of the SCAQMD Governing Board amending Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines.

WHEREAS, the SCAQMD Governing Board finds and determines that the proposed amendments to Rule 1110.2 are considered a "project" pursuant to the California Environmental Quality Act (CEQA); and

WHEREAS, the SCAQMD has had its regulatory program certified pursuant to Public Resources Code § 21080.5 and has conducted CEQA review and analysis pursuant to such program (SCAQMD Rule 110); and

WHEREAS, SCAQMD staff has prepared a Draft Subsequent Environmental Assessment (SEA) pursuant to its certified regulatory program and pursuant to CEQA Guidelines §15252, setting forth the potential environmental consequences of Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines; and

WHEREAS, the Draft SEA was circulated for 45-day public review and comment period from September 1, 2015 to October 16, 2015; and

WHEREAS, no comment letters were received during the comment period relative to the analysis presented in the Draft SEA and the Draft SEA has been revised such that it is now a Final SEA; and

WHEREAS, it is necessary that the adequacy of the Final SEA be determined by the SCAQMD Governing Board prior to its certification; and

WHEREAS, it is necessary that the SCAQMD prepare Findings and a Statement of Overriding Considerations pursuant to CEQA Guidelines §15091 and §15093, respectively, regarding potentially significant adverse environmental impacts that cannot be mitigated to insignificance; and

WHEREAS, no feasible mitigation measures were identified to reduce or eliminate significant adverse operational air quality impacts to less than significant and, as such, a Mitigation Monitoring Plan pursuant to Public Resources Code §21081.6 was not required; and

WHEREAS, the SCAQMD Governing Board voting on Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines has reviewed and considered the Final EA prior to its certification; and

WHEREAS, the SCAQMD Governing Board finds and determines, taking into consideration the factors in § (d)(4)(D) of the Governing Board Procedures (to be codified as Section 30.5(4)(D) of the Administrative Code), that the modifications which have been made to Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, since notice of public hearing was published do not significantly change the meaning of the proposed project within the meaning of Health and Safety Code § 40726 and would not constitute significant new information requiring recirculation of the Draft CEQA document pursuant to CEQA Guidelines § 15088.5; and

WHEREAS, the SCAQMD Governing Board has determined that a need exists to amend Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, for the reasons contained in the Board Letter; and

WHEREAS, the SCAQMD Governing Board has determined that there is a problem, that the proposed amendments to Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines will alleviate (Health and Safety Code § 40001(c)). Specifically, there is a need for additional time for biogas engines to meet the technology-advancing limits earlier imposed, and there is an issue of SIP approvability due to the existing breakdown provisions; and

WHEREAS, the SCAQMD Governing Board obtains its authority to adopt, amend, or rescind rules and regulations from Sections 40000, 40001, 40440, 40500, 40501.3, 40506, 40510, 40510.5, 40512, 40522, 40522.5, 40523, 40702, 40725 through 40728, and 44380 of the California Health and Safety Code; and

WHEREAS, Health and Safety Code §40727 requires that prior to adopting, amending or repealing a rule or regulation, the SCAQMD Governing Board shall make findings of necessity, authority, clarity, consistency, non-duplication, and

WHEREAS, the SCAQMD Governing Board has determined that Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, as proposed to be amended, is written or displayed so that its meaning can be easily understood by the persons directly affected by it; and

WHEREAS, the SCAQMD Governing Board has determined that Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, as proposed to be amended, is in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, or state or federal regulations; and

WHEREAS, the SCAQMD Governing Board has determined that Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, as proposed to be amended, does not impose the same requirements as any existing state or federal regulation, and the proposed amended rule is necessary and proper to execute the powers and duties granted to, and imposed upon, the SCAQMD; and

WHEREAS, the SCAQMD Governing Board, in amending and adopting this regulation, references the following statutes which the District hereby implements, interprets, or makes specific: California Health and Safety Code Sections 40440(a) (rules to carry out the Air Quality Management Plan), 40440(c) (cost effectiveness), 41508, 41700, and Federal Clean Air Act Section 172(c)(1) (RACT); and

WHEREAS, the SCAQMD Governing Board has determined that the Final Socioeconomic Assessment approved for the 2008 amendments to Rule 1110.2 remain valid for this proposed amendment, since there are fewer engines to control and the control costs have remained relatively constant since the 2008 Socioeconomic Assessment was conducted; and

WHEREAS, the SCAQMD Governing Board has determined that the 2008 Socioeconomic Assessment for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines is still consistent with the provisions of Health and Safety Code Sections 40440.8, 40728.5 and 40920.6; and

WHEREAS, the SCAQMD Governing Board has determined that the 2008 Socioeconomic Assessment for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines is still consistent with the March 17, 1989 Board Socioeconomic Resolution for rule adoption; and

WHEREAS, the SCAQMD Governing Board has determined that Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines would have fewer costs to the affected industries than what was described in the 2008 Socioeconomic Assessment; and

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

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

WHEREAS, the SCAQMD specifies the Manager of Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines as the custodian of the documents or other materials which constitute the record of proceedings upon which the adoption of this proposed amendment is based, which are located at the South Coast Air Quality Management District, 21865 Copley Drive, Diamond Bar, California; and

WHEREAS, at the conclusion of the public hearing, the SCAQMD Board may make other amendments to Proposed Amended Rule 1110.2 which are justified by the evidence presented, or may decline the amendments or adoption; and

NOW, THEREFORE, BE IT RESOLVED, that the SCAQMD Governing Board does hereby certify that the Final SEA for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, was completed in compliance with CEQA and Rule 110 provisions; and that the Final SEA was presented to the SCAQMD Governing Board, whose members reviewed, considered and approved the information therein prior to acting on Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines; and

BE IT FURTHER RESOLVED, that the SCAQMD Governing Board adopts the Findings and Statement of Overriding Considerations pursuant to CEQA Guidelines §15091 and §15093, respectively; and

BE IT FURTHER RESOLVED, that the SCAQMD Governing Board hereby directs the Executive Officer to submit Rule 1110.2, as currently amended, for inclusion into the California State Implementation Plan; and

BE IT FUTHER RESOLVED, that the SCAQMD Governing Board directs staff to apply the funds collected from the Compliance Flexibility Fee to the SCAQMD's leaf blower program and any other similar NOx reduction programs pursuant to protocols approved under District rules which staff determines, in consultation with District Counsel, will not call for the preparation of a subsequent environmental assessment pursuant to CEQA guidelines section 15162; and

BE IT FURTHER RESOLVED, that the SCAQMD Governing Board does hereby amend, pursuant to the authority granted by law, Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, as set forth in the attached and incorporated herein by this reference.

Date:____________________ ______________________________________

Clerk of the Boards

ATTACHMENT 1

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Attachment 1 to the Governing Board Resolution for:
Final Subsequent Environmental Assessment for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines

Findings and Statement of Overriding Considerations

SCAQMD No. 150728CC
State Clearinghouse No: 2015071072

December 2015

Executive Officer
Barry R. Wallerstein, D. Env.

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

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

Planning and Rules Manager
Planning, Rule Development and Area Sources
Ian MacMillan

Author:	Cynthia A. Carter	Air Quality Specialist, CEQA
	Jeff Inabinet	Air Quality Specialist, CEQA
Technical Assistance:	Kevin Orellana	Air Quality Specialist
Reviewed By:	Jillian Wong, Ph.D.	Program Supervisor, CEQA
	Gary Quinn	Program Supervisor
	Barbara Baird	Chief Deputy Counsel
	William Wong	Principal Deputy District Counsel

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
GOVERNING BOARD

TABLE OF CONTENTS

INTRODUCTION

Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, is considered a "project" as defined by the California Environmental Quality Act (CEQA) (California Public Resources Code §§21000 et seq.). The South Coast Air Quality Management District (SCAQMD) as Lead Agency for the proposed project, prepared a Notice of Preparation/Initial Study (NOP/IS) which identified environmental topics to be analyzed in a Draft Subsequent Environmental Assessment (SEA). The NOP/IS provided information about the proposed project to other public agencies and interested parties prior to the release of the Draft SEA. The initial evaluation in the NOP/IS identified the topic of air quality and greenhouse gas emissions as potentially being adversely affected by the proposed project. The NOP/IS was distributed to responsible agencies and interested parties for a 30-day public review and comment period from July 29, 2015 to August 27, 2015. During that public comment period, the SCAQMD received no comment letters.

The Draft SEA was prepared as a public disclosure document intended to: (a) provide the lead agency, responsible agencies, decision makers and the general public with information on the environmental impacts of the proposed project; and, (b) be used as a tool by decision makers to facilitate decision making on the proposed project. The Draft SEA was released for a 45-day public review and comment period from September 1, 2015 to October 16, 2015. The Draft SEA, was prepared pursuant to CEQA Guidelines §15161, and evaluated the topic of air quality and greenhouse gas emissions as an area that may be adversely affected by the proposed project. The Draft SEA concluded that only the topic of operational air quality and greenhouse gas emissions impacts would have significant adverse impacts. During that public comment period, the SCAQMD received no comment letters.

CERTIFICATION OF THE FINAL SEA

The SCAQMD Governing Board certifies that it has been presented with the Final SEA for Proposed Amended Rule (PAR) 1110.2 and that it has reviewed and considered the information contained in the Final SEA prior to making the following certifications and findings. Pursuant to CEQA Guidelines §15090 (Title 14 of the California Code of Regulations, §15090), the SCAQMD Governing Board certifies that the Final SEA has been completed in compliance with the CEQA statutes and the CEQA Guidelines. The SCAQMD Governing Board certifies the Final SEA for the actions described in these findings and in the Final SEA, i.e., the proposed project. The SCAQMD Governing Board further certifies that the Final SEA reflects its independent judgment and analysis. The Governing Board Resolution includes the certification of the Final SEA.

SUMMARY OF THE PROPOSED PROJECT

The SCAQMD is proposing to amend Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines. Currently, Rule 1110.2 limits emissions of nitrogen oxides (NOx), volatile organic compounds (VOCs) and carbon monoxide (CO) from the combustion of gaseous and liquid fueled engines. This rule applies to engines that are operating in the SCAQMD and are rated more than 50 brake horsepower (bhp). The rule was adopted in 1990 and last amended in 2012 to establish an effective date of January 1, 2016 for owners and operators of biogas engines to meet the emission limits that all other engines under this rule were required to meet in July 1, 2011.

There are two key issues to be resolved in this amendment:

1. SCAQMD staff's recent evaluation of the state of compliance with Rule 1110.2 as well as feedback from industry revealed that some equipment owners/operators are experiencing compliance challenges, in particular, with certain effective dates in the rule. Because some control technologies have not matured in a timely manner for biogas engines, SCAQMD staff is proposing to amend Rule 1110.2 to delay implementation of NOx, VOC, and CO emission limit compliance dates for biogas engines. The delayed emission reductions are greater than the SCAQMD's mass daily operational significance thresholds for NOx, VOC, and CO, thus the air quality impacts from PAR 1110.2 are considered significant. However, all emission reductions will be recaptured over time, so the impacts are not permanent.
2. Limits are being proposed on the number of breakdowns and excess emissions during breakdown events in order to be consistent with the EPA's breakdown provisions and to allow the rule to be included in the State Implementation Plan (SIP).

<u>Project Objectives</u>

CEQA Guidelines §15124(b) requires the project description to include a statement of objectives sought by the proposed project, including the underlying purpose of the proposed project. Compatibility with project objectives is one criterion for selecting a range of reasonable project alternatives and provides a standard against which to measure project alternatives. The project objectives identified in the following bullet points have been developed: 1) in compliance with CEQA Guidelines §15124 (b); and, 2) to be consistent with policy objectives of the SCAQMD's New Source Review program. The project objectives are as follows:

- to maintain the lower limits on NOx, VOC, and CO emissions from the combustion of gaseous and liquid biogas engines;
- place biogas engines on a more suitable compliance schedule with achievable emission limitations due to the fact that retrofit construction schedules may extend beyond the current compliance deadline and demonstration project control technologies have not matured in a timely manner for these types of engines;
- to comply with EPA Breakdown provision requirements; and
- aside from temporary air quality impacts, avoid generating any new adverse environmental impacts.

SIGNIFICANT ADVERSE IMPACTS WHICH CAN BE REDUCED BELOW A SIGNIFICANT LEVEL OR WERE CONCLUDED TO BE INSIGIFICANT

The Final SEA identified air quality and greenhouse gas emissions as an area that may be adversely affected by the proposed project. The proposed project was evaluated according to the CEQA environmental checklist of approximately 17 environmental topics for potential adverse impacts from a proposed project. The screening analysis concluded that the following environmental areas would not be significantly adversely affected by the proposed project:

- aesthetics
- agriculture and forestry resources
- biological resources
- cultural resources
- energy
- geology and soils
- hazards and hazardous materials
- hydrology and water quality
- land use and planning
- mineral resources
- noise
- population and housing
- public services
- recreation
- solid/hazardous waste
- transportation/traffic

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

The Final SEA identified the topic of operational air quality and greenhouse gas emissions as the only area that may be significantly adversely affected by the proposed project and could not identify and quantify enough feasible mitigation measures to adequately reduce potential impacts to less than significant.

<u>Operational Air Quality</u>

NOx, CO, and VOC emission reductions from PAR 1110.2 will be delayed and will result in approximately 0.9 tons per day of NOx, 0.5 tons per day of VOC, and 20 tons per day of CO emissions delayed by 2019. The quantity of peak daily NOx, VOC, and CO emission reductions delayed exceeds the SCAQMD CEQA significance thresholds for operation. Thus, PAR 1110.2 will result in adverse significant operational air quality impacts.

It should be noted, however, PAR 1110.2 also includes options for alternate compliance plans, and a compliance flexibility fee option that currently exists in Rule 1110.2. In Rule 1110.2, all mitigation fees are used to reduce NOx emissions through the SCAQMD's leaf blower exchange program. The fees collected as a result of the implementation of PAR 1110.2 from the affected facilities electing to use the mitigation fee option will be used in the same manner as fees collected for Rule 1110.2. By funding this program, emission reductions will be generated that provide a regional air quality and corresponding GHG benefit to reduce the impact from the potential delay in emission reductions from those facilities choosing to delay compliance. It is possible that the use of these fees will fully offset the adverse air quality impact, but this cannot be foreseen at this time. No further feasible mitigation measures are identified at this time that would reduce or eliminate the expected foregone emission reductions. Consequently, the operational air quality emission impacts from the proposed project cannot be mitigated to less than significant.

Even though the proposed project could result in emission reductions delayed during operation that exceeds the applicable operational air quality significance thresholds, they are not expected to interfere with the air quality progress and attainment demonstration projected in the AQMP or cause a cumulative impact. Based on regional modeling analyses performed for the 2012 AQMP, implementing control measures contained in the 2012 AQMP, in addition to the air quality benefits of the existing rules, it is anticipated that the South Coast air basin will be in attainment with all national and most state ambient air quality standards by the year 2023. Therefore, when cumulative operational air quality impacts from the proposed project, previous amendments, and all other AQMP control measures are considered together, cumulative impacts are not expected to be significant because implementation of all AQMP control measures is expected to result in net emission reductions and overall air quality improvement. This determination is consistent with the conclusion in the 2012 AQMP Final Program EIR that direct cumulative air quality impacts from implementing all AQMP control measures are not expected to be significant (SCAQMD, 2012). For these aforementioned reasons, the proposed project would not result in irreversible environmental changes or an irretrievable commitment of resources.

FINDINGS

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

NOx, VOC, and CO emission reductions from PAR 1110.2 will be delayed as compared with Rule 1110.2 (current applicable rule), and will result in approximately 0.9 tons per day of NOx, 0.5 tons per day of VOC, and 20 tons per day of CO emissions delayed by 2019 as a result of the compliance extension date.

<u>Finding and Explanation</u>:

PAR 1110.2 is concluded to result in adverse significant operational NOx, VOC and CO air quality impacts as a result of a “worst case” scenario analysis. The significant adverse environmental impacts are identified in a CEQA document; and the CEQA document described all feasible measures that could minimize the impacts of the proposed project.

The affected equipment consists of all stationary and portable engines over 50 rated brake horsepower within the SCAQMD jurisdiction. More specifically, the delayed emissions stems from the biogas fueled engines. This equipment is currently regulated by SCAQMD Rule 1110.2. Due to the fact that control technologies have not matured in a timely manner to retrofit biogas engines, the proposed project would place the affected equipment on a more suitable compliance schedule with achievable emission limitations under a new proposed rule. The proposed project would delay the compliance dates outlined in Rule 1110.2, and therefore, there would be adjustments to the annual operational NOx emission reductions during the varying compliance years. The proposed project will result in approximately 0.9 tons per day of peak daily NOx, 0.5 tons per day of VOC, and 20 tons per day of CO emissions delayed by 2019 as a result of the delay in compliance dates.

PAR 1110.2 also includes options for alternate compliance plans, equipment certification and a mitigation fee option to delay compliance. The alternate compliance option allows facilities to phase in compliance for equipment over one year. The mitigation fee option provides facilities an option to delay compliance by up to three years. However, the air quality analysis presented in the Final SEA represents a "worst case" analysis and accounts for these potential additional delays in compliance.

The mitigation fee option for PAR 1110.2 is the same mitigation fee program that currently exists in Rule 1110.2, which is available to the affected sources. In Rule 1110.2, all mitigation fees are used to reduce NOx emissions through the SCAQMD's leaf blower exchange program. The fees collected as a result of the implementation of PAR 1110.2 from the affected facilities electing to use the mitigation fee option will be used in the same manner as fees collected for Rule 1110.2. Emission reductions funded through the mitigation fee alternative compliance option can be achieved through a variety of projects including but not limited to replacement of commercial leaf blowers with low emission or electric units, replacement of gas powered lawnmowers with electric mowers, automobile scrapping, co-funding with Carl Moyer or similar programs or purchasing of emission reduction credits or mobile source emission reduction credits for the relevant time period. By funding this program, emission reductions will be generated that provide a regional air quality improvement and GHG co-benefit, to reduce the impact from the potential delay in emission reductions from those facilities choosing to delay compliance. It is possible that the use of these fees will fully offset the adverse air quality impact, but this cannot be foreseen at this time. However, it could be anticipated that those taking advantage of the mitigation fee option under Rule 1110.2 would also participate under PAR 1110.2, thus similar emission reductions would result. There are no further feasible mitigation measures identified at this time that would reduce or eliminate the expected delay in emission reductions. Consequently, the operational air quality emissions impacts from the proposed project cannot be mitigated to less than significant.

The Governing Board finds that no feasible mitigation measures have been identified that would mitigate the potentially significant adverse impacts to operational air quality to less than significant levels. CEQA defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors" (Public Resources Code §21061.1).

The Governing Board finds further that the Final SEA considered alternatives, pursuant to CEQA Guidelines §15126.6. The proposed project was considered to provide the best balance between meeting the objectives of the project while minimizing potentially significant adverse environmental impacts. The administrative record for the CEQA document and adoption of the rule is maintained by the SCAQMD Office of Planning, Rule Development and Area Sources.

<u>Conclusion</u>

The Governing Board finds that the findings required by CEQA Guidelines §15091(a) are supported by substantial evidence in the record. The record of approval for this project may be found in the SCAQMD's Clerk of the Board's Office located at SCAQMD headquarters in Diamond Bar, California.

STATEMENT OF OVERRIDING CONSIDERATIONS

If significant adverse impacts of a proposed project remain after incorporating mitigation measures, or no measures or alternatives to mitigate the adverse impacts are identified, the lead agency must make a determination that the benefits of the project outweigh the unavoidable adverse environmental effects if it is to approve the project. CEQA requires the decision-making agency to balance, as applicable, the economic, legal, social, technological, or other benefits, including region-wide or statewide environmental benefits, of a proposed project against its unavoidable environmental risks when determining whether to approve the project [CEQA Guidelines §15093(a)]. If the specific economic, legal, social, technological, or other benefits, including region-wide or statewide environmental benefits, of a proposed project outweigh the unavoidable adverse environmental effects, the adverse environmental effects may be considered "acceptable" [CEQA Guidelines §15093 (a)]. Accordingly, a Statement of Overriding Considerations regarding potentially significant adverse operational NOx, VOC, and CO air quality impacts resulting from the "worst case" analysis of the proposed project has been prepared. This Statement of Overriding Considerations is included as part of the record of the project approval for the proposed project. Pursuant to CEQA Guidelines §15093(c), the Statement of Overriding Considerations will also be noted in the Notice of Decision for the proposed project.

Despite the inability to incorporate changes into the proposed project that will mitigate potentially significant adverse operational air quality impacts to a level of insignificance, the SCAQMD's Governing Board finds that the following benefits and considerations outweigh the potentially significant unavoidable adverse environmental impacts:

1. The analysis of potential adverse environmental impacts incorporates a "worst case" approach. This entails the premise that whenever the analysis requires that assumptions be made, those assumptions that result in the greatest adverse impacts are typically chosen. This method likely overestimates the actual emission reductions delayed from the proposed project.
2. PAR 1110.2 would place biogas engines on a more suitable compliance schedule with achievable emission limitations due to the fact that control technologies have not matured in a timely manner for this particular category of equipment.
3. The fees collected from the affected facilities electing to use the mitigation fee option will be used in the same manner as fees collected for Rule 1110.2. By funding this program, emission reductions will be generated that provide a regional air quality and corresponding GHG benefit to reduce the impact from the potential delay in emission reductions from those facilities choosing to delay compliance. It is possible that the use of these fees will fully offset the adverse air quality impact, but this cannot be foreseen at this time.

4. Supplemental projects funded by the mitigation fee option will reduce emissions from the proposed project and will aid the advancement of technology, which will facilitate compliance with the 8-hour ozone standard and the annual PM2.5 standard.
5. By maximizing funding for air quality improvement programs with the mitigation fee from the proposed project, emission reductions will be generated that provide local and regional air quality benefits to reduce the impact of the potential delay in emission reductions from those facilities choosing to delay compliance.

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

MITIGATION

CEQA requires an agency to prepare a plan for reporting and monitoring compliance with the implementation of measures to mitigate significant adverse environmental impacts. Mitigation monitoring requirements are included in CEQA Guidelines §15097 and Public Resources Code §21081.6, which specifically state:

When making findings as required by subdivision (a) of Public Resources Code §21081 or when adopting a negative declaration pursuant to paragraph (2) of subdivision (c) of Public Resources Code §21080, the public agency shall adopt a reporting or monitoring program for the changes to the project which it has adopted or made a condition of project approval in order to mitigate or avoid significant effects on the environment (Public Resources Code §21081.6). The reporting or monitoring program shall be designed to ensure compliance during project implementation. For those changes which have been required or incorporated into the project at the request of an agency having jurisdiction by law over natural resources affected by the project, that agency shall, if so requested by the lead or responsible agency, prepare and submit a proposed reporting or monitoring program.

The provisions of CEQA Guidelines §15097 and Public Resources Code §21081.6 are triggered when the lead agency certifies a CEQA document in which mitigation measures, changes, or alterations have been required or incorporated into the project to avoid or lessen the significance of adverse impacts identified in the CEQA document. However, since no feasible mitigation measures to fully reduce significant adverse operational NOx, VOC, and CO air quality impacts were identified, a mitigation monitoring and reporting plan for operations is not required. However, fees collected from the affected facilities electing to use the mitigation fee option will be used in the same manner as fees collected for Rule 1110.2. By funding this program, emission reductions will be generated that provide a regional air quality and corresponding GHG benefit to reduce the impact from the potential delay in emission reductions from those facilities choosing to delay compliance. It is possible that the use of these fees will fully offset the adverse air quality impact, but this cannot be foreseen at this time.

CONCLUSION

Based on a "worst case" analysis, the potential adverse operational air quality impacts from the adoption and implementation of the proposed project are considered significant and unavoidable.

NOx, VOC, and CO emission reductions from PAR 1110.2 are delayed compared with Rule 1110.2, and will result in approximately 0.9 tons per day of peak daily NOx, 0.5 tons per day of VOC, and 20 tons per day of CO emissions delayed by 2019 as a result of the delay in compliance dates.

However, PAR 1110.2 also includes options for alternate compliance plans, equipment certification and a mitigation fee option that currently exists in Rule 1110.2. In Rule 1110.2, all mitigation fees are used to reduce NOx emissions through the SCAQMD's leaf blower exchange program. The fees collected as a result of the implementation of PAR 1110.2 from the affected facilities electing to use the mitigation fee option will be used in the same manner as fees collected for Rule 1110.2. Emission reductions funded through the mitigation fee alternative compliance option can be achieved through a variety of projects including but not limited to replacement of commercial leaf blowers with low emission or electric units, replacement of gas powered lawnmowers with electric mowers, automobile scrapping, co-funding with Carl Moyer or similar programs or purchasing of emission reduction credits or mobile source emission reduction credits for the relevant time period. By funding these programs, emission reductions will be generated that provide a regional air quality and corresponding GHG benefit to reduce the impact from the potential delay in emission reductions from those facilities choosing to delay compliance. It is possible that the use of these fees will fully offset the adverse air quality impacts, but this cannot be foreseen at this time. No additional feasible mitigation measures or project alternatives have been identified that would reduce these impacts to insignificance.

(Adopted August 3, 1990)(Amended September 7, 1990)(Amended August 12, 1994)
(Amended December 9, 1994)(Amended November 14, 1997)
(Amended June 3, 2005)(Amended February 1, 2008)(Amended July 9, 2010)
(Amended September 7, 2012)(PAR 1110.2 December 4, 2015)

PROPOSED AMENDED RULE 1110.2 EMISSIONS FROM GASEOUS- AND LIQUID-FUELED ENGINES

(a) Purpose

The purpose of Rule 1110.2 is to reduce Oxides of Nitrogen (NO_x), Volatile Organic Compounds (VOCs), and Carbon Monoxide (CO) from engines.

(b) Applicability

All stationary and portable engines over 50 rated brake horsepower (bhp) are subject to this rule

(c) Definitions

For the purpose of this rule, the following definitions shall apply:

(1) AGRICULTURAL STATIONARY ENGINE is a non-portable engine used for the growing and harvesting of crops of the raising of fowl or animals for the primary purpose of making a profit, providing a livelihood, or conducting agricultural research or instruction by an educational institution. An engine used for the processing or distribution of crops or fowl or animals is not an agricultural engine.

(2) APPROVED EMISSION CONTROL PLAN is a control plan, submitted on or before December 31, 1992, and approved by the Executive Officer prior to November 14, 1997, that was required by subdivision (d) of this rule as amended September 7, 1990.

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

(4~~3~~) CERTIFIED SPARK-IGNITION ENGINE means engines certified by California Air Resources Board (CARB) to meet emission standards in accordance with Title 13, Chapter 9, Article 4.5 of the California Code of Regulations (CCR).

(5~~4~~) EMERGENCY STANDBY ENGINE is an engine which operates as a temporary replacement for primary mechanical or electrical power during periods of fuel or energy shortage or while the primary power supply is under repair.

(6~~5~~) ENGINE is any spark- or compression-ignited internal combustion engine, including engines used for control of VOC's, but not including engines used for self-propulsion.

(7~~6~~) EXEMPT COMPOUNDS are defined in District Rule 102 – Definition of Terms.

(8~~7~~) FACILITY means any source or group of sources or other air contaminant emitting activities which are located on one or more contiguous properties within the District, in actual physical contact or separated solely by a public roadway or other public right-of-way, and are owned or operated by the same person (or by persons under common control), or an outer continental shelf (OCS) source as determined in Section 55.2 of Title 40, Part 55 of the Code of Federal Regulations (40 CFR Part 55). Such above-described groups, if noncontiguous, but connected only by land carrying a pipeline, shall not be considered one facility. Sources or installations involved in crude oil and gas production in Southern California Coastal or OCS Waters and transport of such crude oil and gas in Southern California Coastal or OCS Waters shall be included in the same facility which is under the same ownership or use entitlement as the crude oil and gas production facility on-shore.

(9~~8~~) LEAN-BURN ENGINE means an engine that operates with high levels of excess air and an exhaust oxygen concentration of greater than 4 percent.

(10~~9~~) LOCATION means any single site at a building, structure, facility, or installation. For the purpose of this definition, a site is a space occupied or to be occupied by an engine. For engines which are brought to a facility to perform maintenance on equipment at its permanent or ordinary location, each maintenance site shall be a separate location.

(11~~0~~) NET ELECTRICAL ENERGY means the electrical energy produced by a generator, less the electrical energy consumed by any auxiliary equipment necessary to operate the engine generator and, if applicable, any heat recovery equipment, such as heat exchangers.

(12~~1~~ NON-ROAD ENGINE is any engine, defined under 40 CFR Part 89, that

) does not remain or will not remain at a location for more than 12 consecutive months, or a shorter period of time where such period is representative of normal annual source operation at a stationary source that resides at a fixed location for more than 12 months (e.g., seasonal operations such as canning facilities), and meets one of the following:

(A) Is used in or on a piece of equipment that is self-propelled or serves a dual purpose by both propelling itself and performing another function (such as a mobile crane); or

(B) Is used in or on a piece of equipment that is intended to be propelled while performing its function (such as lawn mowers and string trimmers); or

(C) By itself, or in or on a piece of equipment, is portable or transportable, meaning designed to be and capable of being carried or moved from one location to another. Transportability includes, but is not limited to, wheels, skids, carrying handles, dolly, trailer, platform or mounting.

(13~~2~~) OPERATING CYCLE means a period of time within which a round of regularly recurring events is completed, and cannot be stopped without the risk of endangering public safety or health, causing material damage to the equipment or product, or cannot be stopped due to technical constraints. Economic reasons alone will not be sufficient to extend this time period. The operating cycle includes batch processes that may start and finish several times within a twenty-four hour period, in which case each start to finish interval is considered a complete cycle.

(14~~3~~) OXIDES OF NITROGEN (NOx) means nitric oxide and nitrogen dioxide.

(15~~4~~) PORTABLE ENGINE is an engine that, by itself or in or on a piece of equipment, is designed to be and capable of being carried or moved from one location to another. Indications of portability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, platform or mounting. The operator must demonstrate the necessity of the engine being periodically moved from one location to another because of the nature of the operation.

An engine is not portable if:

(A) the engine or its replacement remains or will reside at the same location for more than 12 consecutive months. Any engine, such as a back-up or stand-by engine, that replaces an engine at a location and is intended to perform the same function as the engine being replaced, will be included in calculating the consecutive time period. In that case, the cumulative time of both engines, including the time between the removal of the original engine and installation of the replacement engine, will be counted toward the consecutive time period; or

(B) the engine remains or will reside at a location for less than 12 consecutive months where such a period represents the full length of normal annual source operations such as a seasonal source; or

(C) the engine is removed from one location for a period and then it or its equivalent is returned to the same location thereby circumventing the portable engine residence time requirements.

The period during which the engine is maintained at a designated storage facility shall be excluded from the residency time determination.

(16~~5~~) RATED BRAKE HORSEPOWER (bhp) is the rating specified by the manufacturer, without regard to any derating, and listed on the engine nameplate.

(17~~6~~) RICH-BURN ENGINE WITH A THREE-WAY CATALYST means an engine designed to operate near stoichiometric conditions with a catalytic control device that simultaneously reduces emissions of NOx, CO and VOC.

(18~~7~~) STATIONARY ENGINE is an engine which is either attached to a foundation or if not so attached, does not meet the definition of a portable or non-road engine and is not a motor vehicle as defined in Section 415 of the California Vehicle Code.

(19~~8~~) TIER 2 AND TIER 3 DIESEL ENGINES mean engines certified by CARB to meet Tier 2 or Tier 3 emission standards in accordance with Title 13, Chapter 9, Article 4 of the CCR.

(20~~19~~) USEFUL HEAT RECOVERED means the waste heat recovered from the engine exhaust and/or cooling system that is put to productive use. The waste heat recovered may by assumed to be 100% useful unless the hot water, steam or other medium is vented to the atmosphere, or sent directly to a cooling tower or other unproductive use.

(21~~0~~) VOLATILE ORGANIC COMPOUND (VOC) is as defined in Rule 102.

(d) Requirements

(1) Stationary Engines:

(A) Operators of stationary engines with an amended Rule 1110.1 Emission Control Plan submitted by July 1, 1991, or an Approved Emission Control Plan, designating the permanent removal of engines or the replacement of engines with electric motors, in accordance with subparagraph (d)(1)(B), shall do so by December 31, 1999, or not operate the engines on or after December 31, 1999 in a manner that exceeds the emission concentration limits listed in Table I:

TABLE I ALTERNATIVE TO ELECTRIFICATION CONCENTRATION LIMITS		
NO_x	VOC	CO
(ppmvd)[1] 11	(ppmvd)[2] 30	(ppmvd)[1] 70

[1] Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

[2] Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

(B) The operator of any other stationary engine not covered by (d)(1)(A) and not exempt from this rule shall

(i) Remove such engine permanently from service or replace the engine with an electric motor, or

(ii) Not operate the engine in a manner that exceeds the applicable emission concentration limits listed in either Table II or Table III-A or B.

TABLE II CONCENTRATION LIMITS		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 36 bhp < 500: 45	250	2000
CONCENTRATION LIMITS EFFECTIVE JULY 1, 2010		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 11 bhp < 500: 45	bhp ≥ 500: 30 bhp < 500: 250	bhp ≥ 500: 250 bhp < 500: 2000
CONCENTRATION LIMITS EFFECTIVE JULY 1, 2011		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250

1 Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

2 Parts per million by volume, measured as carbon**,** corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

The concentration limits effective on and after July 1, 2010 shall not apply to engines that operate less than 500 hours per year or use less than 1 x 10^9 British Thermal Units (Btus) per year (higher heating value) of fuel.

If the operator of a two-stroke engine equipped with an oxidation catalyst and insulated exhaust ducts and catalyst housing demonstrates that the CO and VOC limits effective on and after July 1, 2010 are not achievable, then the Executive Officer may, with United States Environmental Protection Agency (EPA) approval, establish technologically achievable, case-by-case CO and VOC limits in place of the concentration limits effective on and after July 1, 2010. The case-by-case limits shall not exceed 250 ppmvd VOC and 2000 ppmvd CO.

If the operator of an engine that uses non-pipeline quality natural gas demonstrates that due to the varying heating value of the gas a longer averaging time is necessary, the Executive Officer may establish for the engine a longer averaging time, not to exceed six hours, for any of the concentration limits of Table II. Non-pipeline quality natural gas is a gas that does not meet the gas specifications of the local gas utility and is not supplied to the local gas utility.

(C) The operator of any stationary engine fired by landfill or digester gas (biogas) shall not operate the engine in a manner that exceeds the emission concentration limits of Table III-A, provided that the facility monthly average biogas usage by the biogas engine is 90% or more, based on the higher heating value of the fuels used. The calculation of the monthly facility biogas use percentage may exclude natural gas fired during: any electrical outage at the facility; a Stage 2 or higher electrical emergencies called by the California Independent System Operator Corporation; and when a sewage treatment plant activates an Emergency Operations Center or Incident Command System, as part of an emergency response plan, because of either high influent flows caused by precipitation or a disaster.

TABLE III-A
CONCENTRATION LIMITS FOR LANDFILL AND DIGESTER GAS (BIOGAS)-FIRED ENGINES

NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 36 x ECF[3] bhp < 500: 45 x ECF[3]	Landfill Gas: 40 Digester Gas: 250 x ECF[3]	2000

TABLE III-B
CONCENTRATION LIMITS EFFECTIVE JANUARY 1, 2017~~6~~

NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250

1 Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

2 Parts per million by volume, measured as carbon**,** corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

3 ECF is the efficiency correction factor.

The ECF shall be 1.0 unless:

(i) The engine operator has measured the engine's net specific energy consumption (q_a), in compliance with ASME Performance Test Code PTC 17 -1973, at the average load of the engine; and

(ii) The ECF-corrected emission limit is made a condition of the engine's permit to operate.

The ECF is as follows:

$$ECF = \frac{9250 \text{ Btus/hp-hr}}{\text{Measured } q_a \text{ in Btus/hp-hr}}$$

Measured q_a shall be based on the lower heating value of the fuel. ECF shall not be less than 1.0.

The Executive Officer may approve the burning of more than 10% natural gas in a landfill or digester gas-fired engine, when it is necessary, if: the only alternative to limiting natural gas to 10%

would be shutting down the engine and flaring more landfill or digester gas; or the engine requires more natural gas in order for a waste heat recovery boiler to provide enough thermal energy to operate a sewage treatment plant, and other boilers at the facility are unable to provide the necessary thermal energy.

(D) Notwithstanding the provisions of subparagraph (d)(1)(B), the operator of any stationary engine fired by landfill or digester gas (biogas) shall not operate the engine in a manner that exceeds the emission concentration limits of Table III.

(E) Biogas engine operators that establish to the satisfaction of the Executive Officer that they have complied with the emissions limits of Table III-B by January 1, 2015 will have their respective engine permit application fees refunded.

(F) For the City of San Bernardino, Orange County Sanitation District, and Eastern Municipal Water District that commenced and implemented technology demonstration projects prior to January 1, 2015, all their biogas engines shall have until January 1, 2018 to comply with the requirements of Table III-B.

(G~~F~~) Once an engine complies with the concentration limits as specified in Table III-B, there shall be no limit on the percentage of natural gas burned.

(H~~G~~) The concentration limits effective as specified in Table III-B shall not apply to engines that operate fewer than 500 hours per year or use less than 1 x 10^9 Btus per year (higher heating value) of fuel.

(I~~H~~) An operator of a biogas engine may determine compliance with the NOx and/or CO limits of Table III-B by utilizing a longer averaging time as set forth below, provided the operator demonstrates through CEMS data that the engine is achieving a concentration at or below 9.9 ppmv for NOx and 225 ppmv for CO (if CO is elected for averaging), each corrected to 15% O_2, over a 4 month time period. An operator may utilize a monthly fixed interval averaging time for the first 4 months of the retrofitted engine's operation and up to a 24 hour fixed interval averaging time thereafter. For purposes of determining compliance using a longer averaging time:

(i) An operator shall not average data during one-minute periods in which the underlying equipment is not operated or when the CEMS is undergoing zero or calibration checks, cylinder gas audits, or routine maintenance in accordance with the provisions in Rules 218 and 218.1.

(ii) Notwithstanding the requirements of Rules 218 and 218.1, for one-minute time periods where NOx and/or CO CEMS data are greater than 95 percent of the Rule 218.1 Full Scale Range while the underlying equipment is operating, an operator shall use substitute data. A concentration equivalent to 3 times the NOx and/or CO emission limits in Table III-B (each corrected to 15% O2) shall be used as substitute data.

(iii) The intentional shutdown of a CEMS to circumvent the emission limits of Table III-B while the underlying equipment is in operation shall constitute a violation of this rule.

(iv) The averaging provisions of this subparagraph shall not apply to CEMS that are time shared by multiple biogas engines.

(J~~I~~) The operator of any new engine subject to subparagraph (e)(1)(B) shall:

(i) Comply with the requirements of Best Available Control Technology in accordance with Regulation XIII if the engine requires a District permit; or

(ii) Not operate the engine in a manner that exceeds the emission concentration limits in Table I if the engine does not require a District permit.

(K~~J~~) By February 1, 2009, the operator of a spark-ignited engine without a Rule 218-approved continuous emission monitoring system (CEMS) or a Regulation XX (RECLAIM)-approved CEMS shall equip and maintain the engine with an air-to-fuel ratio controller with an oxygen sensor and feedback control, or other equivalent technology approved by the Executive Officer, CARB and EPA.

(L~~K~~) New Non-Emergency Electrical Generators

(i) All new non-emergency engines driving electrical-generators shall comply with the following emission standards:

TABLE IV EMISSION STANDARDS FOR NEW ELECTRICAL GENERATION DEVICES	
Pollutant	**Emission Standard (lbs/MW-hr)[1]**
NOx	0.070
CO	0.20
VOC	0. 10[2]

1. The averaging time of the emission standards is 15 minutes for NOx and CO and the sampling time required by the test method for VOC, except as described in the following clause.
2. Mass emissions of VOC shall be calculated using a ratio of 16.04 pounds of VOC per lb-mole of carbon.

(ii) Engines subject to this subparagraph that produce combined heat and electrical power may include one megawatt-hour (MW-hr) for each 3.4 million Btus of useful heat recovered (MW_{th}-hr), in addition to each MW-hr of net electricity produced (MW_e-hr). The compliance of such engines shall be based on the following equation:

$$\frac{Lbs}{MW\text{-}hr} = \frac{Lbs}{MW_e\text{-}hr} \times \text{Electrical Energy Factor (EEF)}$$

Where:

Lbs/MW-hr = The calculated emissions that shall comply with the emission standards in Table IV

Lbs/MW_e-hr = The short-term engine emission limit in pounds per MWe-hr of net electrical energy produced, averaged over 15 minutes. The engine shall comply with this limit at all times.

EEF = The annual MW_e-hrs of net electrical energy produced divided by the sum of annual MW_e-hrs plus annual MW_{th}-hrs of useful heat recovered. The engine operator shall demonstrate annually that the EEF is less than the value required for compliance.

(iii) For combined heat and power engines, the short-term emission limits in lbs/MW_e-hr and the maximum allowed annual EEF must be selected by operator and stated on the operating permit.

(iv) Notwithstanding Rule 2001, the requirements of this subparagraph shall apply to NOx emissions from new non-emergency engines driving electrical-generators subject to Regulation XX (RECLAIM).

(v) This subparagraph does not apply to: engines installed prior to February 1, 2008; engines issued a permit to construct prior to February 1, 2008 and installed within 12 months of the date of the permit to construct; engines for which an application is deemed complete by October 1, 2007; engines installed by an electric utility on Santa Catalina Island; engines installed at remote locations without access to natural gas and electric power; engines used to supply electrical power to ocean-going vessels while at berth, prior to January 1, 2014; or landfill or digester gas-fired engines that meet the requirements of subparagraph (d)(1)(C).

(2) Portable Engines:

(A) The operator of any portable engine generator subject to this rule shall not use the portable generator for:

(i) Power production into the electric grid, except to maintain grid stability during an emergency event or other unforeseen event that affects grid stability; or

(ii) Primary or supplemental power to a building, facility, stationary source, or stationary equipment, except during unforeseen interruptions of electrical power from the serving utility, maintenance and repair operations, and remote operations where grid power is unavailable. For interruptions of electrical power, the operation of a portable generator shall not exceed the time of the actual interruption of power.

This subparagraph shall not apply to a portable generator that complies with emission concentration limits of Table I and the other requirements in this rule applicable to stationary engines.

(B) The operator of any portable diesel engine shall comply with the applicable requirements of the Subchapter 7.5 Airborne Toxic Control Measures for diesel particulate matter in Chapter 1, Division 3, Title 17 of the California Code of Regulations.

(C) The operator of any portable spark-ignited engine shall comply with the applicable requirements of the Large Spark Ignition Engine Fleet Requirements, Article 2, Chapter 15, Division 3, Title 13 of the California Code of Regulations.

(e) Compliance

(1) Agricultural Stationary Engines:

(A) The operator of any agricultural stationary engine subject to this rule and installed or issued a permit to construct prior to June 3, 2005 shall comply with subparagraph (d)(1)(B) and the other applicable provisions of this rule in accordance with the compliance schedules in Table V:

TABLE V
COMPLIANCE SCHEDULES FOR STATIONARY AGRICULTURAL ENGINES

Action Required	**Tier 2 and Tier 3 Diesel Engines, Certified Spark-Ignition Engines, and All Engines at Facilities with Actual Emissions Less Than the Amounts in the Table of Rule 219(q)**	**Other Engines**
Submit notification of applicability to the Executive Officer	January 1, 2006	January 1, 2006
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	March 1, 2009	September 1, 2007
Initiate construction of engine modifications, control equipment, or replacement engines	September 30, 2009, or 30 days after the permit to construct is issued, whichever is later	March 30, 2008, or 30 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	January 1, 2010, or 60 days after the permit to construct is issued, whichever is later	July 1, 2008, or 60 days after the permit to construct is issued, whichever is later
Complete initial source testing	March 1, 2010, or 120 days after the permit to construct is issued, whichever is later	September 1, 2008, or 120 days after the permit to construct is issued, whichever is later

The notification of applicability shall include the following for each engine:

(i) Name and mailing address of the operator

(ii) Address of the engine location

(iii) Manufacturer, model, serial number, and date of manufacture of the engine

(iv) Application number

(v) Engine type (diesel, rich-burn spark-ignition or lean-burn spark-ignition)

(vi) Engine fuel type

(vii) Engine use (pump, compressor, generator, or other)

(viii) Expected means of compliance (engine replacement, control equipment installation, or electrification)

(B) The operator of any new agricultural stationary engine that is not subject to the compliance schedule of subparagraph (e)(1)(A) for existing engines shall comply with the requirements of subparagraph (d)(1)(J~~I~~) immediately upon installation.

(2) Non-Agricultural Stationary Engines:

(A) The operator of any stationary engine not meeting the requirements of subparagraphs (d)(1)(B) or (d)(1)(C) that go into effect in 2010 or later, shall comply with the compliance schedule in Table VI:

TABLE VI
COMPLIANCE SCHEDULE FOR NON -AGRICULTURAL STATIONARY ENGINES

Action Required	Applicable Compliance Date
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	Twelve months before the final compliance date
Initiate construction of engine modifications, control equipment, or replacement engines	Three months before the final compliance date, or 60 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	The final compliance date, or 120 days after the permit to construct is issued, whichever is later
Complete initial source testing	60 days after the final compliance date in (d)(1)(B) or (d)(1)(C), or 180 days after the permit to construct is issued, whichever is later

(B) The operator of any stationary engine that elects to amend a permit to operate to incorporate ECF-adjusted emission limits shall submit to the Executive Officer an application for a change of permit conditions by August 1, 2008, and comply with emission limits of the previous version of this rule until February 1, 2009 when the engine shall be in compliance with the emission limits of this rule.

(C) The operator of any stationary engine that is required to add operating restrictions to a permit to operate to meet the requirements of this rule shall submit to the Executive Officer an application for a change of permit conditions by August 1, 2008.

(3) Stationary Engine CEMS

(A) The operator of any stationary engine with an existing CEMS shall commence the reporting required by Rule 218 Subdivision (f) on January 1, 2008. The first summary report for the six months ending June 30, 2008 shall be due on July 30, 2008.

(B) The operator of any stationary engine that is required to modify an existing CEMS or install a CEMS on an existing engine shall comply with the compliance schedule in Table VII. Public agencies shall be allowed one year more than the dates in Table VII, except for biogas engines.

TABLE VII
COMPLIANCE SCHEDULE FOR NEW OR MODIFIED CEMS ON EXISTING ENGINES

	Applicable Compliance Dates For:		
Action Required	**Non-Biogas Engines Rated at 750 bhp or More**	**Non-Biogas Engines Rated at Less than 750 bhp**	**Biogas Engines***
Submit to the Executive Officer applications for new or modified CEMS	August 1, 2008	August 1, 2009	January 1, 2011
Complete installation and commence CEMS operation, calibration, and reporting requirements	Within 180 days of initial approval	Within 180 days of initial approval	Within 180 days of initial approval
Complete certification tests	Within 90 days of installation	Within 90 days of installation	Within 90 days of installation

TABLE VII COMPLIANCE SCHEDULE FOR NEW OR MODIFIED CEMS ON EXISTING ENGINES			
	Applicable Compliance Dates For:		
Action Required	**Non-Biogas Engines Rated at 750 bhp or More**	**Non-Biogas Engines Rated at Less than 750 bhp**	**Biogas Engines***
Submit certification reports to Executive Officer	Within 45 days after tests are completed	Within 45 days after tests are completed	Within 45 days after tests are completed
Obtain final approval of CEMS	Within 1 year of initial approval	Within 1 year of initial approval	Within 1 year of initial approval

* A biogas engine is one that is subject to the emission limits of Table III.

(4) Stationary Engine Inspection and Monitoring (I&M) Plans:

The operator of stationary engines subject to the I&M plan provisions of subparagraph (f)(1)(D) shall:

(A) By August 1, 2008, submit an initial I&M plan application to the Executive Officer for approval;

(B) By December 1, 2008, implement an approved I&M plan or the I&M plan as submitted if the plan is not yet approved.

Any operator of 15 or more stationary engines subject to the I&M plan provisions shall comply with the above schedule for at least 50% of engines, and for the remaining engines shall:

(C) By February 1, 2009, submit an initial I&M plan application to the Executive Officer for approval;

(D) By June 1, 2009, implement an approved I&M plan or the I&M plan as submitted if the plan is not yet approved.

(5) Stationary Engine Air-to-Fuel Ratio Controllers

(A) The operator of any stationary engine that does not have an air-to-fuel ratio controller, as required by subparagraph (d)(1)(K~~J~~), shall comply with those requirements in accordance with the compliance schedule in Table V, except that the application due date is no later than May 1, 2008 and the initial source testing may be conducted at the time of the testing required by subparagraph (f)(1)(C).

(B) The operator of any stationary engine that has the air-to-fuel ratio controller required by subparagraph (d)(1)(K~~J~~), but it is not listed on the permit to operate, shall submit to the Executive Officer an application to amend the permit by April 1, 2008.

(C) The operator of more than five engines that do not have air-to-fuel ratio controllers may take an additional three months, to May 1, 2009, to install the equipment on up to 50% of the affected engines.

(6) New Stationary Engines

The operator of any new stationary engine issued a permit to construct after February 1, 2008 shall comply with the applicable I&M or CEMS requirements of this rule when operation commences. If applicable, the operator shall provide the required information in subparagraph (f)(1)(D) to the Executive Officer prior to the issuance of the permit to construct so that the I&M procedures can be included in the permit. A separate I&M plan application is not required.

(7) Biogas Engines

For any biogas engine for which the operator applies to the Executive Officer by April 1, 2008 for a change of permit conditions for ECF-corrected emission limits, or the approval to burn more than 10 percent natural gas in accordance with subparagraph (d)(1)(C), the biogas engine shall not be subject to the initial concentration limits of Tables II or III until August 1, 2008, provided the operator continues to comply with all emission limits in effect prior to February 1, 2008.

(8) Compliance Schedule Exception

If an engine operator submits to the Executive Officer an application for an administrative change of permit conditions to add a permit condition that causes the engine permit to expire by the effective date of any requirement of this rule, then the operator is not required to comply with the earlier steps required by this subdivision for that requirement. The effective date for the CEMS requirements shall be one year after the date that a CEMS application is due.

(9) Exceedance of Usage Limits

(A) If an engine was initially exempt from the new concentration limits in subparagraph (d)(1)(B) or subparagraph (d)(1)(C) that take effect on or after July 1, 2010 because of low engine use but later exceeds the low-use criteria, the operator shall bring the engine into compliance with the rule in accordance with the schedule in Table VI with the final compliance date in Table VI being twelve months after the conclusion of the first twelve-month period for which the engine exceeds the low-use criteria.

(B) If engines that were initially exempt from new CEMS by the low-use criterion in subclause (f)(1)(A)(ii)(I) later exceed that criterion, the operator shall install CEMS on those engines in accordance with the schedule in Table VII, except that the date for submitting the CEMS application in Table VII shall be six months after the conclusion of the first twelve-month period for which the engines exceed the criterion.

(f) Monitoring, Testing, Recordkeeping and Reporting

(1) Stationary engines:

The operator of any engine subject to the provisions of paragraph (d)(1) of this rule shall meet the following requirements:

(A) Continuous Emission Monitoring

(i) For engines of 1000 bhp and greater and operating more than two million bhp-hr per calendar year, a NO_x and CO continuous emission monitoring system (CEMS) shall be installed, operated and maintained in calibration to demonstrate compliance with the emission limits of this rule.

(ii) (I) For facilities with engines subject to paragraph (d)(1), having a combined rating of 1500 bhp or greater at the same location, and having a combined fuel usage of more than 16 x 10^9 Btus per year (higher heating value), CEMS shall be installed, operated and maintained in calibration to demonstrate compliance of those engines with the applicable NO_x and CO emission limits of this rule.

(II) Any engine that as of October 1, 2007 is located within 75 feet of another engine (measured from engine block to engine block) is considered to be at the same location. Operators of new engines shall not install engines farther than 75 feet from another engine unless the operator demonstrates to the Executive Officer that operational needs or space limitations require it.

(III) The following engines shall not be counted toward the combined rating or required to have a CEMS by this clause: engines rated at less than 500 bhp; standby engines that are limited by permit conditions to only operate when other primary engines are not operable; engines that are limited by permit conditions to operate less than 1000 hours per year or a fuel usage of less than 8 x 10^9 Btus per year (higher heating value of all fuels used); engines that are used primarily to fuel public natural gas transit vehicles and that are required by a permit condition to be irreversibly removed from service by December 31, 2014; and engines required to have a CEMS by the previous clause. A CEMS shall not be required if permit conditions limit the simultaneous use of the engines at the same location in a manner to limit the combined rating of all engines in simultaneous operation to less than 1500 bhp.

(IV) For engines rated below 1000 bhp, the CEMS may be time shared by multiple engines.

(V) Operation of engines by the electric utility in the Big Bear Lake area during the failure of a transmission line to the utility may be excluded from an hours-per-year or fuel usage limit that is elected by the operator pursuant to subclause (f)(1)(A)(ii)(III).

(VI) In lieu of complying with subclause (f)(1)(A)(ii)(I), an operator that is a public agency, or is contracted to operate engines solely for a public agency, may comply with the Inspection and Monitoring Plan requirements of subparagraph (f)(1)(D), except that the operator shall conduct diagnostic emission checks at least weekly or every 150 operating hours, whichever occurs later. If any such engine is found to exceed an applicable NOx or CO limit by a source test required by subparagraph (f)(1)(C) or District test using a portable analyzer on three or more occasions in any 12-month period, the operator shall comply with the CEMS requirements of this subparagraph for such engine in accordance with the compliance schedule of Table VII, except that the operator shall submit a CEMS application to the Executive Officer within six months of the third exceedance.

(iii) All CEMS required by this rule shall:

(I) Comply with the applicable requirements of Rule 218 and 218.1, including equipment specifications and certification, operating, recordkeeping, quality assurance and reporting requirements, except as otherwise authorized by this rule;

(II) Include equipment that measures and records exhaust gas concentrations, both uncorrected and corrected to 15 percent oxygen on a dry basis; and

(III) Have data gathering and retrieval capability approved by the Executive Officer

(iv) The operator of an engine that is required to install CEMS may request the Executive Officer to approve an alternative monitoring device (or system components) to demonstrate compliance with the emission limits of this rule. The applicant shall demonstrate to the Executive Officer that the proposed alternative monitoring device is at a minimum equivalent in relative accuracy, precision, reliability, and timeliness to a CEMS for that engine, according to the criteria specified in 40 CFR Part 75 Subpart E. In lieu of the criteria specified in 40 CFR Part 75 Subpart E, substitute criteria is acceptable if the applicant demonstrates to the Executive Officer that the proposed alternative monitoring device is at minimum equivalent in relative accuracy, precision, reliability, and timeliness to a CEMS for that engine. Upon approval by the Executive Officer, the substitute criteria shall be submitted to EPA as an amendment to the State Implementation Plan (SIP).

If the alternative monitoring device is denied or fails to be recertified, a CEMS shall be required.

(v) Notwithstanding the requirements of Rules 218 and 218.1, operators of engines that are required to install a CEMS by clause (f)(1)(A)(ii) of this subparagraph may:

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

(II) Conduct relative accuracy testing on the same schedule for source testing in clause (f)(1)(C)(i), instead of annually. The minimum sampling time for each test is 15 minutes.

(vi) Notwithstanding the requirements of Rules 218 and 218.1, operators of engines that are required to install a CEMS by clause (ii) of this subparagraph, and that are to be monitored by a timeshared CEMS, may:

(I) Monitor an engine with the CEMS for 15 consecutive minutes, purge for the minimum required purge time, then monitor the next engine for 15 consecutive minutes. The CEMS shall operate continuously in this manner, except for required calibrations.

(II) Record the corrected and uncorrected NOx, CO and diluent data at least once per minute and calculate and record the 15-minute average corrected concentrations for each sampling period.

(III) Have sample lines to each engine that are not the same length. The purge time will be based on the sample line with the longest response time. Response times shall be checked during cylinder gas audits. Sample lines shall not exceed 100 feet in length.

(IV) Conduct a minimum of five tests for each engine during relative accuracy tests.

(V) Perform a cylinder gas audit every calendar quarter on each engine, except for engines for which relative accuracy testing was conducted that quarter.

(VI) Exclude monitoring of nitrogen dioxide (NO_2) for rich-burn engines, unless source testing demonstrates that NO_2 is more than 10 percent of total NOx.

(VII) Conduct daily calibration error (CE) tests by injecting calibration gases at the analyzers, except that at least once per week the CE test shall be conducted by injecting calibration gases as close to the probe tip as practical.

(VIII) Stop operating and calibrating the CEMs during any period that the operator has a continuous record that the engine was not in operation.

(vii) A CO CEMS shall not be required for lean-burn engines or an engine that is subject to Regulation XX (RECLAIM), and not required to have a NOx CEMS by that regulation.

(viii) Notwithstanding the requirements of this paragraph and paragraph (c)(2) of Rule 2012, an operator may take an existing NOx CEMS out of service for up to two weeks (cumulative) in order to modify the CEMS to add CO monitoring.

(B) Elapsed Time Meter

Maintain an operational non-resettable totalizing time meter to determine the engine elapsed operating time.

(C) Source Testing

(i) Effective August 1, 2008, conduct source testing for NO_x, VOC reported as carbon, and CO concentrations (concentrations in ppm by volume, corrected to 15 percent oxygen on dry basis) at least once every two years, or every 8,760 operating hours, whichever occurs first. Relative accuracy tests required by Rule 218.1 or 40 CFR Part 75 Subpart E will satisfy this requirement for those pollutants monitored by a CEMS. The source test frequency may be reduced to once every three years if the engine has operated less than 2,000 hours since the last source test. If the engine has not been operated within three months of the date a source test is required, the source test shall be conducted when the engine resumes operation for a period longer than either seven consecutive days or 15 cumulative days of operation. The operator of the engine shall keep sufficient operating records to demonstrate that it meets the requirements for extension of the source testing deadlines.

(ii) Conduct source testing for at least 30 minutes during normal operation (actual duty cycle). This test shall not be conducted under a steady-state condition unless it is the normal operation. In addition, conduct source testing for NOx and CO emissions for at least 15 minutes at: an engine's actual peak load, or the maximum load that can be practically achieved during the test, and; at actual minimum load, excluding idle, or the minimum load that can be practically achieved during the test. These additional two tests are not required if the permit limits the engine to operating at one defined load, ± 10%. No pre-tests for compliance are permitted. The emission test shall be conducted at least 40 operating hours, or at least 1 week, after any engine servicing or tuning. If an emission exceedance is found during any of the three phases of the test, that phase shall be completed and reported. The operator shall correct the exceedance, and the source test may be immediately resumed.

(iii) Use a contractor to conduct the source testing that is approved by the Executive Officer under the Laboratory Approval Program for the necessary test methods.

(iv) Submit a source test protocol to the Executive Officer for written approval at least 60 days before the scheduled date of the test. The source test protocol shall include the name, address and phone number of the engine operator and a District-approved source testing contractor that will conduct the test, the application and permit number(s), emission limits, a description of the engine(s) to be tested, the test methods and procedures to be used, the number of tests to be conducted and under what loads, the required minimum sampling time for the VOC test, based on the analytical detection limit and expected VOC levels, and a description of the parameters to be measured in accordance with the I&M plan required by subparagraph (f)(1)(D). The source test protocol shall be approved by the Executive Officer prior to any testing. The operator is not required to submit a protocol for approval if: there is a previously approved protocol that meets these requirements; the engine has not been altered in a manner that requires a permit alteration; and emission limits have not changed since the previous test. If the operator submits the protocol by the required date, and the Executive Officer takes longer than 60 days to approve the protocol, the operator shall be allowed the additional time needed to conduct the test.

(v) Provide the Executive Officer at least 30 days prior notice of any source test to afford the Executive Officer the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the engine operator shall notify the Executive Officer as soon as possible of any delay in the original test date, either by providing at least seven days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Executive Officer by mutual agreement.

(vi) Submit all source test reports, including a description of the equipment tested, to the Executive Officer within 60 days of completion of the test.

(vii) By February 1, 2009, provide, or cause to be provided, source testing facilities as follows:

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

(II) Safe sampling platform(s), scaffolding or mechanical lifts, including safe access, that comply with California General Safety Orders. Agricultural stationary engines are excused from this subclause if they are in remote locations without electrical power;

(III) Utilities for sampling and testing equipment. Agricultural stationary engines are exempt from this subclause if they are on wheels and moved to storage during the off season.

(D) Inspection and Monitoring (I&M) Requirements~~Plan~~

(i) I&M Plan. The operator shall:

(I) Submit to the Executive Officer for written approval an I&M plan. One plan application is required for each facility that does not have a NOx and CO CEMS for each engine. The I&M plan shall include all items listed in Attachment 1.

(II) Upon written approval by the Executive Officer, implement the I&M plan as approved.

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

(ii) Diagnostic emission checks by a portable NOx, CO, and oxygen analyzer shall be conducted at least weekly or every 150 engine operating hours, whichever occurs later.

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

(II) For diesel engines and other lean-burn engines that are subject to Regulation XX or have a NOx CEMs, and that are subject to a CO limit more stringent than the 2000 ppmvd limit of Tables II or III, a CO diagnostic emission check shall be performed at least quarterly, or every 2,000 engine operating hours, whichever occurs later.

(III) For diesel engines and other lean-burn engines that are subject to Regulation XX or have a NOx CEMs, and that are not subject to a CO limit more stringent than the 2000 ppmvd limit of Tables II or III, diagnostic emission checks are not required.

(IV) No engine or control system maintenance or tuning may be conducted within 72 hours prior to the diagnostic emission check, unless it is an unscheduled, required repair.

(V) The portable analyzer shall be calibrated, maintained and operated in accordance with the manufacturer's specifications and recommendations and the Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Stationary Engines Subject to South Coast Air Quality Management District Rule 1110.2, approved on February 1, 2008, or subsequent protocol approved by EPA and the Executive Officer.

~~Submit to the Executive Officer for written approval and implement an I&M plan. One plan application is required for each facility. The I&M plan shall include:~~

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

~~(I) Procedures for using a portable NOx, CO and oxygen analyzer to establish the set points of the air-to-fuel ratio controller (AFRC) at 25%, 60% and 95% load (or fuel flow rate), ± 5%, or the minimum, midpoint and maximum loads that actually occur during normal operation, ± 5%, or at any one load within the ± 10% range that an engine permit is limited to in accordance with clause (f)(1)(C)(ii);~~

~~(II) Procedures for verifying that the AFRC is controlling the engine to the set point during the daily monitoring required by clause (f)(1)(D)(iv);~~

~~(III) Procedures for reestablishing all AFRC set points with a portable NOx, CO and oxygen analyzer whenever a set point must be readjusted, within 24 hours of an oxygen sensor replacement, and, for rich-burn engines with three way catalysts, between 100 and 150 engine operating hours after an oxygen~~

~~sensor replacement;~~

~~(IV) For engines with catalysts, the maximum allowed exhaust temperature at the catalyst inlet, based on catalyst manufacturer specifications;~~

~~(V) For lean-burn engines with selective catalytic control devices, the minimum exhaust temperature at the catalyst inlet required for reactant flow (ammonia or urea), and procedures for using a portable NOx and oxygen analyzer to establish the acceptable range of reactant flow rate, as a function of load.~~

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

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

~~(iii) Procedures for at least weekly or every 150 engine operating hours, whichever occurs later, emissions checks by a portable NOx, CO and oxygen analyzer.~~

~~(I) If an engine is in compliance for three consecutive emission checks, without any adjustments to the oxygen sensor set points, then the engine may be checked monthly or every 750 engine operating hours, whichever occurs later, until there is a noncompliant emission check or, for rich-burn engines with three-way catalysts, the oxygen sensor is replaced. When making adjustments to the oxygen sensor set points, returning to a more frequent emission check schedule is not required if the engine is in compliance with the applicable emission limits prior to and after the set point adjustments, notwithstanding the requirements of (f)(1)(D)(iii)(IV).~~

~~(II) For diesel engines and other lean-burn engines that are subject to Regulation XX or have a NOx CEMs, and that are subject to a CO limit more stringent than the 2000 ppmvd limit of Tables II or III, a CO emission check shall be performed at least quarterly, or every 2,000 engine operating hours, whichever occurs later.~~

~~(III) For diesel engines and other lean-burn engines that are subject to Regulation XX or have a NOx CEMs, and that are not subject to a CO limit more stringent than the 2000 ppmvd limit of Tables II or III, emission checks are not required.~~

~~(IV) No engine or control system maintenance or tuning may be conducted within 72 hours prior to the emission check, unless it is an unscheduled, required repair.~~

~~(V) The portable analyzer shall be calibrated, maintained and operated in accordance with the manufacturer's specifications and recommendations and the Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Stationary Engines Subject to South Coast Air Quality Management District Rule 1110.2, approved on February 1, 2008, or subsequent protocol approved by EPA and the Executive Officer.~~

~~(iv) Procedures for at least daily monitoring, inspection and recordkeeping of:~~

~~(I) engine load or fuel flow rate;~~

~~(II) the set points, maximums and acceptable ranges of the parameters identified by clause (f)(1)(D)(i), and the actual values of the same parameters;~~

~~(III) the engine elapsed time meter operating hours;~~

~~(IV) the operating hours since the last emission check required by clause (f)(1)(D)(iii);~~

~~(V) for rich-burn engines with three-way catalysts, the difference of the exhaust temperatures (ΔT) at the inlet and outlet of the catalyst (changes in the ΔT can indicate changes in the effectiveness of the catalyst);~~

~~(VI) engine control system and AFRC system faults or alarms that affect emissions.~~

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

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

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

(II) For excess emissions due to breakdowns that result in NOx or CO emissions greater than the concentrations specified in Table VIII, the operator shall not be considered in violation of this rule if the operator demonstrates the all of the following: (1) compliance with subclause (f)(1)(D)(iii)(I), (2) compliance with the reporting requirements of subparagraph (f)(1)(H), and (3) the engine with excess emissions has no more than three incidences of breakdowns with emissions exceeding Table VIII limits in the calendar quarter.

TABLE VIII Excess Emission Concentration Thresholds for Breakdowns		
	NO_x (ppmvd)[1]	CO (ppmvd)[1]
Lean-Burn Engines	45	250
Rich-Burn Engines	150	2000
Biogas Engines[2]	185	2000

1 Corrected to 15% oxygen.

2 Effective up to the time of compliance with the limits specified in Table III-B, after which the thresholds revert to the applicable lean or rich-burn engine limits.

(III) Any emission check conducted by District staff that finds excess emissions will be treated as a violation.

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

~~(III) An operator shall not be considered in violation of the emission limits of this rule or in permit conditions if the operator complies with this subparagraph and the reporting requirements of subparagraph (f)(1)(H). Any emission check conducted by District staff that finds excess emissions is a violation.~~

~~(vi) Procedures and schedules for preventive and corrective maintenance.~~

~~(vii) Procedures for reporting noncompliance to the Executive Officer in accordance with subparagraph (f)(1)(H).~~

~~(viii) Procedures and format for the recordkeeping of monitoring and other actions required by the plan.~~

~~(ix) Procedures for plan revisions. Before any change in I&M plan operations can be implemented, the revised I&M plan shall be submitted to and approved by the Executive~~

~~Officer. The operator shall apply for a plan revision prior to any change in emission limits or control equipment.~~

~~(x)~~ ~~An engine is not subject to this subparagraph if it is required by this rule to have a NOx and CO CEMS, or voluntarily has a NOx and CO CEMS that complies with this rule.~~

(iv) If an engine has a NOx CEMS and does not have a CO CEMS, it is subject to this subparagraph (f)(1)(D) as it pertains to CO only.

(E) Operating Log

Maintain a monthly engine operating log that includes:

(i) Total hours of operation;

(ii) Type of liquid and/or type of gaseous fuel;

(iii) Fuel consumption (cubic feet of gas and gallons of liquid); and

(iv) Cumulative hours of operation since the last source test required in subparagraph (f)(1)(C).

Facilities subject to Regulation XX may maintain a quarterly log for engines that are designated as a process unit on the facility permit.

(F) New Non-Emergency Electrical Generating Engines

Operators of engines subject to the requirements of subparagraph (d)(1)(L~~K~~) shall also meet the following requirements.

(i) The engine generator shall be monitored with a calibrated electric meter that measures the net electrical output of the engine generator system, which is the difference between the electrical output of the generator and the electricity consumed by the auxiliary equipment necessary to operate the engine generator.

(ii) For engines monitored with a CEMS, the emissions of the monitored pollutants in ppmvd corrected to 15% O2, lbs/hr, and lbs/MW_e-hr and the net MW_e-hrs produced shall be calculated and recorded for the four 15-minute periods of each hour of operation. The mass emissions of NOx shall be calculated based on the measured fuel flow and one of the F factor methods of 40 CFR 60, Appendix A, Method 19, or other method approved by the Executive Officer. Mass emissions of CO shall be calculated in the same manner as NOx, except that the ppmvd CO shall be converted to lb/scf using a conversion factor of 0.727×10^{-7}.

(iii) For NOx and CO emissions from engines not monitored with a CEMS and VOC emissions from all engines, the emissions of NOx, CO and VOC in lbs/MW_e-hr shall be calculated and recorded whenever the pollutant is measured by a source test or diagnostic emission check. Mass emissions of NOx and CO shall be calculated in the same manner as the previous clause. Mass emissions of VOC shall be calculated in the same manner, except that the ppmvd VOC as carbon shall be converted to lb/scf using a conversion factor of 0.415×10^{-7}.

(iv) For engines generating combined heat and power that rely on the EEF to comply with Table IV emission standards, the daily and annual useful heat recovered (MW_{th}-hrs), net electrical energy generated (MW_e-hrs) and EEF shall be monitored and recorded.

(v) Other methods of calculating mass emissions than those specified, such as by direct measurement of exhaust volume, may be used if approved by the Executive Officer. All monitoring, calculation, and recordkeeping procedures must be approved by the Executive Officer.

(vi) Operators of combined heat and power engines shall submit to the Executive Officer the reports of the following information within 15 days of the end of the first year of operation, and thereafter within 15 days of the end of each calendar year: the annual net electrical energy generated (MW_e-hrs); the annual useful heat recovered (MW_{th}-hrs), the annual EEF calculated in accordance with clause (d)(1)(L~~K~~)(ii); and the maximum annual EEF allowed by the operating permit. If the actual annual EEF exceeds the allowed EEF, the report shall also include the time periods and emissions for all instances where emissions exceeded any emission standard in Table IV.

(G) Portable Analyzer Operator Training

The portable analyzer tests required by the I&M Plan requirements of subparagraph (f)(1)(D) shall only be conducted by a person who has completed an appropriate District-approved training program in the operation of portable analyzers and has received a certification issued by the District.

(H) Reporting Requirements

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

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

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

(II) The duration of the breakdown;

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

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

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

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

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

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

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

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

(2) Portable engines:

The operator of any portable engine shall maintain a monthly engine operating log that includes:

(i) Total hours of operation; or

(ii) Type of liquid and/or type of gaseous fuel; and

(iii) Fuel consumption (cubic feet of gas and gallons of liquid).

Facilities subject to Regulation XX may maintain a quarterly log for engines that are designated as a process unit on the facility permit.

(3) Recordkeeping for All Engines

All data, logs, test reports and other information required by this rule shall be maintained for at least five years and made available for inspection by the Executive Officer.

(g) Test Methods

Testing to verify compliance with the applicable requirements shall be conducted in accordance with the test methods specified in Table IX~~VIII~~, or any test methods approved by CARB and EPA, and authorized by the Executive Officer.

TABLE IX~~VIII~~

TESTING METHODS

Pollutant	Method
NO_x	District Method 100.1
CO	District Method 100.1
VOC	District Method 25.1* or District Method 25.3*

* Excluding ethane and methane

A violation of any standard of this rule established by any of the specified test methods, or any test methods approved by the CARB or EPA, and authorized by the Executive Officer, shall constitute a violation of this rule.

(h) Alternate Compliance Option

(1) In lieu of complying with the applicable emission limits by the effective date specified in Table III-B or subparagraph (d)(1)(F), owners or operators of biogas-fired units may elect to defer compliance in quarterly increments up to one additional year, provided the owner or operator: ~~In lieu of complying with the applicable emission limits by the effective date~~

~~specified in Table III-B, owners or operators of biogas-fired units that operate under long term fixed price power purchase agreements that have been entered into prior to February 1, 2008 and extend beyond January 1, 2016 may elect to defer compliance by up to two years and no later than January 1, 2018, provided the owner or operator:~~

(A) Submits an alternate compliance plan and pays a Compliance Flexibility Fee, as provided for in paragraph (h)(2), to the Executive Officer at least ~~15~~<u>6</u>0 days prior to the applicable compliance date in <u>either </u>Table III-B~~,~~ <u>or subparagraph (d)(1)(F) for qualified biogas technology demonstration project engines, </u>and

(B) Maintains on-site a copy of verification of Compliance Flexibility Fee payment and AQMD approval of the alternate compliance plan that shall be made available upon request to AQMD staff.

(2) Plan Submittal

The alternate compliance plan submitted pursuant to paragraph (h)(1) shall include:

(A) A completed AQMD Form 400A with company name, AQMD Facility ID, identification that application is for a compliance plan (Section 7a of form), and identification that request is for Rule 1110.2 Compliance Flexibility Fee option (Section 9 of form);

(B) Attached documentation of unit permit ID, unit rated brake horsepower (bhp), and fee calculation;

~~(C) Proof that the power purchase agreement was entered into prior to February 1, 2008 and extends beyond January 1, 2016.~~

(<u>C</u>~~D~~) Filing Fee payment; and

(<u>D</u>~~E~~) Compliance Flexibility Fee payment as calculated by the following equation:

CFF = bhp x R x <u>Q</u>~~Y~~

Where,

CFF = Compliance Flexibility Fee, $

bhp = rated brake horsepower of unit

R = Fee Rate = $<u>11.75</u>~~47~~ per brake horsepower per <u>quarter</u>~~year~~

<u>Q</u>~~Y~~ = Number of <u>quarters</u>~~years~~ (<u>up to four</u>~~up to 2 years for engines~~

~~required to comply by January 1, 2016~~)

(3) Usage of Compliance Flexibility Fee funds

The funds collected from the Compliance Flexibility Fee will be applied to AQMD NOx reduction programs pursuant to protocols approved under District rules.

(i) Exemptions

The provisions of subdivision (d) shall not apply to:

(1) All orchard wind machines powered by an internal combustion engine.

(2) Emergency standby engines, engines used for fire-fighting and flood control, and any other emergency engines approved by the Executive Officer, which have permit conditions that limit operation to 200 hours or less per year as determined by an elapsed operating time meter, and agricultural emergency standby engines that are exempt from a District permit and operate 200 hours or less per year as determined by an elapsed operating time meter.

(3) Laboratory engines used in research and testing purposes.

(4) Engines operated for purposes of performance verification and testing of engines.

(5) Auxiliary engines used to power other engines or gas turbines during start-ups.

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

(7) Nonroad engines, with the exception that subparagraph (d)(2)(A) shall apply to portable generators.

(8) Engines operating on San Clemente Island; and engines operated by the County of Riverside for the purpose of public safety communication at Santa Rosa Peak in Riverside County, where the site is located at an elevation of higher than 7,400 feet above sea level and is without access to electric power and natural gas.

(9) Agricultural stationary engines provided that:

(A) The operator submits documentation to the Executive Officer by the applicable date in Table V when permit applications are due that the applicable electric utility has rejected an application for an electrical line extension to the location of the engines, or the Executive Officer determines that the operator does not qualify, due to no fault of the operator, for funding authorized by California Health and Safety Code Section 44229; and

(B) The operator replaces the engines, in accordance with the compliance schedule of Table ~~I~~X, with engines certified by CARB to meet the Tier 4 emission standards of 40 CFR Part 1039 Section 1039.101, Table 1. These Tier 4 replacement engines shall be considered to comply with Best Available Control Technology; and

(C) The operator does not operate the Tier 4 engines in a manner that exceeds the not-to-exceed standards of 40 CFR Section 1039.101, Paragraph (e), as determined by the test methods of subdivision (g) of this rule.

TABLE ~~I~~X
COMPLIANCE SCHEDULE FOR INSTALLATION OF NEW TIER 4 STATIONARY AGRICULTURAL ENGINES

Action Required	Due Date
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	March 1, 2013
Initiate construction of engine modifications, control equipment, or replacement engines	September 30, 2013, or 30 days after the permit to construct is issued, whichever is later

TABLE ~~I~~X
COMPLIANCE SCHEDULE FOR INSTALLATION OF NEW TIER 4 STATIONARY AGRICULTURAL ENGINES

Action Required	Due Date
Complete construction and comply with applicable requirements	January 1, 2014, or 60 days after the permit to construct is issued, whichever is later
Complete initial source testing	March 1, 2014, or 120 days after the permit to construct is issued, whichever is later

(10) An engine start-up, until sufficient operating temperatures are reached for

proper operation of the emission control equipment, and an engine shutdown period. The periods shall not exceed 30 minutes, unless the Executive Officer approves a longer period not exceeding 2 hours for an engine and makes it a condition of the engine permit.

(11) An engine start-up, after an engine overhaul or major repair requiring removal of a cylinder head, for a period not to exceed four operating hours.

(12) The initial commissioning of a new engine for a period specified by permit conditions, provided the operator takes measures to reduce emissions and the duration of the commissioning to the extent possible. The commissioning period shall not exceed 150 operating hours.

ATTACHMENT 1

An I&M Plan submitted to the Executive Officer for approval and implementation, pursuant to the requirements of (e)(4), (e)(6), and (f)(1)(D) of the rule, shall include:

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

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

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

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

C. Procedures for diagnostic emission checks conducted by a portable NOx, CO, and oxygen analyzer per the requirements of clause (f)(1)(D)(ii) of the rule.

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

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

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

E. Procedures for responding to, diagnosing and correcting breakdowns, faults, malfunctions, alarms, diagnostic emission checks finding emissions in excess of rule or permit limits, and parameters out-of-range, per the requirements of clause (f)(1)(D)(iii) of the rule.

F. Procedures and schedules for preventive and corrective maintenance.

G. Procedures for reporting noncompliance to the Executive Officer in accordance with subparagraph (f)(1)(H) of the rule.

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

ALTERNATIVE RULE PROPOSAL

The following rule language contained in Rule 1110.2 (f)(1)(D)(iii) is an alternative proposal which, based on stakeholder comments, would remove the current rule language (and proposed rule language presented by staff) stating that certain breakdowns are not violations of the rule and adding suggested EPA language making it clear that breakdowns may be subject to federal enforcement, thus satisfying EPA concerns. Below, the staff proposal language is struck out and is replaced by the proposed alternative rule language.

(iii) Requirements for responding to, diagnosing and correcting breakdowns, faults, malfunctions, alarms, diagnostic emission checks finding emissions in excess of rule or permit limits, and parameters out-of-range. Nothing in this clause is intended to exempt any breakdown that otherwise becomes a violation of local, State, or federal requirements.

(I) For any diagnostic emission check or breakdown that results in emissions in excess of those allowed by this rule or a permit condition, the operator shall: (1) correct the problem as soon as possible and demonstrate compliance with another diagnostic emission check, or shut down an engine by the end of an operating cycle, or within 24 hours from the time the operator knew of the breakdown or excess emissions, or reasonable should have known, whichever is sooner, and (2) demonstrate compliance with the reporting requirements of subparagraph (f)(1)(H).

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

~~whichever is sooner.~~

~~(II)~~ ~~For excess emissions due to breakdowns that result in NOx or CO emissions greater than the concentrations specified in Table VIII, the operator shall not be considered in violation of this rule if the operator demonstrates the all of the following: (1) compliance with subclause (f)(1)(D)(iii)(I), (2) compliance with the reporting requirements of subparagraph (f)(1)(H), and (3) the engine with excess emissions has no more than three incidences of breakdowns with emissions exceeding Table VIII limits in the calendar quarter.~~

~~**TABLE VIII**~~

~~Excess Emission Concentration Thresholds for Breakdowns~~

	~~NO_x (ppmvd)~~[1]	~~CO (ppmvd)~~[1]
~~Lean-Burn Engines~~	~~45~~	~~250~~
~~Rich-Burn Engines~~	~~150~~	~~2000~~
~~Biogas Engines~~[2]	~~185~~	~~2000~~

~~1~~ ~~Corrected to 15% oxygen.~~

~~2~~ ~~Effective up to the time of compliance with the limits specified in Table III-B, after which the thresholds revert to the applicable lean or rich-burn engine limits.~~

~~(III)~~(II) Any emission check conducted by District staff that finds excess emissions will be treated as a violation.

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

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Draft Final Staff Report
Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines

December 4, 2015

Executive Officer
Barry R. Wallerstein, D.Env.

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

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

Author:	Kevin Orellana – Air Quality Specialist
Reviewed by:	Gary Quinn, P.E. – Program Supervisor William Wong – Principal Deputy District Counsel
Technical Assistance:	Alfonso Baez, M.S. – Program Supervisor

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
GOVERNING BOARD

TABLE OF CONTENTS

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

The South Coast Air Quality Management District (SCAQMD) is the air pollution control agency for all of Orange County and the urban portions of Los Angeles, Riverside and San Bernardino counties. SCAQMD is responsible for controlling emissions primarily from non-vehicular sources of air pollution.

Rule 1110.2 regulates oxides of nitrogen (NOx), carbon monoxide (CO), and volatile organic compound (VOC) emissions from liquid and gas fueled internal combustion engines operating in the SCAQMD producing more than 50 rated brake horsepower (bhp). The rule was adopted in 1990 and last amended in 2012 to establish an effective date of January 1, 2016 for owners and operators of biogas engines to meet the emission limits that all other engines under this rule were required to meet in July 1, 2011. A Final Technology Assessment was also completed which outlined several technologies for biogas engine emission control along with costs.

Pursuant to the board resolution for the September 7, 2012 amendments to Rule 1110.2, SCAQMD staff has held several meetings with biogas engine stakeholders for updates on the status of both ongoing demonstration projects and the installation of controls. Most of the operators have committed to installing control equipment for biogas engines. However, some biogas engine control installations will take longer than expected and would reach full compliance after the current deadline of January 1, 2016.

In addition, EPA Region 9 brought to SCAQMD staff's attention the breakdown provisions in the July 9, 2010 amended version of Rule 1110.2, which was submitted for SIP approval in 2014. EPA has notified SCAQMD that the breakdown provisions are inconsistent with national policy regarding excess emissions during breakdown conditions, and would prevent full approval of the rule.

The proposed amendments would:

- Establish an effective date of January 1, 2017 for all biogas engines.
- Provide additional time until January 1, 2018 for all biogas engines with the submittal of a compliance plan and payment of a compliance flexibility fee.
- Provide an alternate compliance option to give biogas owners or operators that commenced demonstration projects prior to January 1, 2015 additional time until January 1, 2018 without payment of a compliance flexibility fee, and to January 1, 2019 with payment of a compliance flexibility fee.
- Allow the assessment of the compliance flexibility fee on a quarterly basis.
- Address EPA's concerns with equipment breakdowns and potential excess emissions without enforcement by establishing a limit for exceedances due to breakdowns without enforcement action per calendar quarter.

- Alternative rule language is also being proposed which would remove rule language stating that breakdowns are not violations, thus subjecting operators to potential federal enforcement action or citizen lawsuits.

The project would result in a delay of 0.9 tons per day of NOx reductions, 0.5 tons per day of VOC reductions, and 20 tons per day of CO reductions. The cost effectiveness for the installation of controls would remain unchanged from that presented in the 2012 Final Technology Assessment and Final Staff Report.

CHAPTER 1: BACKGROUND

INTRODUCTION

The California Health and Safety Code requires the AQMD to adopt an Air Quality Management Plan (AQMP) to meet state and federal ambient air quality standards and adopt rules and regulations that carry out the objectives of the AQMP. The California Health and Safety Code also requires the AQMD to implement all feasible measures to reduce air pollution. The 2007 AQMP found that additional reductions are needed to meet the more stringent federal ozone and particulate matter standards. Reductions in NOx and VOC will aid in attaining the ozone standard in 2023. Figure 1 shows the projected baseline emissions for NOx and VOC and the required emissions to achieve the ozone standard in 2023. Further NOx and VOC reductions from Rule 1110.2 biogas engines are essential for achieving compliance with federal and state ambient air quality standards for PM2.5 and ozone.

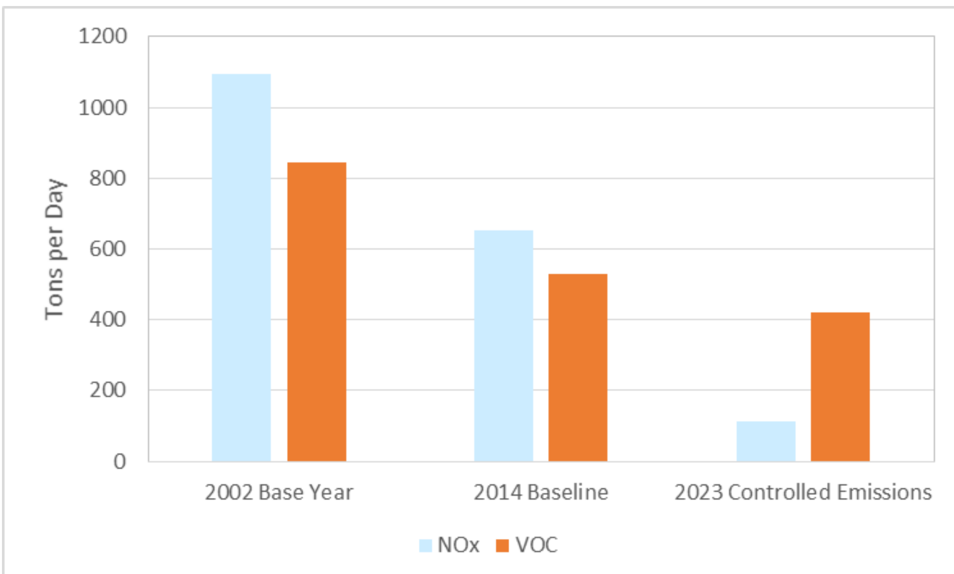

Figure 1. NOx and VOC Baseline Emissions and Emissions Needed to Achieve the 2023 Ozone Standard

Engines that are fueled by biogas (landfill or digester gas) make up about 7% of stationary, non-emergency engines in the AQMD. Landfills produce gas that results from the breakdown of municipal solid waste. This gas is primarily composed of methane and carbon dioxide. The gas is collected in a series of wells that transports it via pipeline to the landfill gas fired engines. The collected landfill gas fires one or more biogas engines with or without supplementation of natural gas.

Wastewater treatment plants produce digester gas from the plant's digesters. A digester uses heat and bacteria in an oxygen-free (anaerobic) environment to break down sewage sludge. A by-product of this process is biogas that contains methane. This biogas also fires one or more biogas engines with or without supplementation of natural gas. An advantage with using ICEs at wastewater treatment plants is that these are combined heat and power (CHP) units. The waste heat created by the engine can be recovered and used to heat the plant's digesters, resulting in energy savings.

Whether coming from a landfill or an anaerobic digester, the biogas is used to fire an internal combustion engine with a generator to produce electricity. Some facilities are self-generating facilities that use the electricity to power their processes internally. Others sell this generated power to the local utility grid. The wastewater treatment plants are primarily operated by public entities and utilities, while the landfills are operated by either public or private operators.

There are currently 58 biogas engines operating in the Basin. Of these engines, 30 are digester gas-fueled and 28 are landfill gas-fueled. These engines are operated by a total of eight public operators and five private operators at 22 locations in the South Coast Basin (6 operate digester gas-fueled engines and 7 operate landfill gas-fueled engines).

Of all the combustion sources, these engines inherently have the highest emissions. Rule 1110.2, "Emissions from Gaseous- and Liquid-Fueled Engines," was first adopted in 1990 to address emissions from stationary engines in this category. Since the rule's adoption, advances in low NOx burner and post combustion control technology have been demonstrated and implemented on several categories of combustion equipment. In contrast, the current NOx concentration BACT and rule limits for biogas engines are at least twelve times higher than allowed by AQMD boiler rules.

Projected NOx emissions reductions from biogas engines achieving the emissions limits set in the 2008 rule amendment were not included in the State Implementation Plan (SIP) because they were contingent on the completion of a Technology Assessment. The Final Technology Assessment was completed as part of the amendments to Rule 1110.2 in 2012. Upon implementation, the NOx reductions from biogas engines will be incorporated into the SIP to further advance the District's efforts towards the attainment of federal and state $PM_{2.5}$ and ozone air quality standards.

REGULATORY HISTORY

Rule 1110.2 – Emissions from Gaseous- and Liquid-Fired Engines was adopted by the AQMD Governing Board on August 3, 1990. It required that either 1) NOx emissions be reduced over 90% to one of two compliance limits specified by the rule, or; 2) the engines be permanently removed from service or replaced with electric motors. It was amended in September 1990 to clarify rule language and then amended in August and December of 1994 to modify the CO monitoring requirements and to clarify rule language. The amendment of November 1997 eliminated the requirement for continuous monitoring of CO, reduced the source testing requirement from once every year to once every three years, and exempted non-road engines, including portable engines, from most requirements. The amendment in June 2005 made the previously exempt agricultural engines subject to the rule.

To address widespread non-compliance with stationary IC engines, the 2008 amendment augmented the source testing, continuous monitoring, inspection and maintenance (I&M), and reporting requirements of the rule to improve compliance. It also required stationary, non-emergency engines to meet emission standards equivalent to current BACT for NOx and VOC and almost to BACT for CO. This partially implemented the 2007 AQMP control measure for Facility Modernization (MCS-001). Additionally, the 2008 amendment required new electric generating engines to limit emissions to levels nearly equivalent to large central power plants, meeting standards that are at or near the CARB 2007 Distributed Generation Emissions Standards. It also clarified the status for portable engines and set emissions standards for biogas engines to become effective on July 1, 2012 if the July 2010 Technology Assessment would confirm the achievability of those limits.

The 2008 adopting resolution included commitments directing staff to conduct a Technology Assessment to address the availability, feasibility, cost-effectiveness, compliance schedule, and global warming gas impacts of biogas engine control technologies and report back to the Governing Board no later than July 2010. Additionally, the Governing Board directed that the July 2012 biogas emission limits would not be incorporated into the SIP unless the July 2010 Technology Assessment found that the proposed limits are achievable and cost-effective.

The amendment in July 2010 added an exemption to the rule affecting a remote public safety communications site at Santa Rosa Peak in Riverside County which has limited accessibility in the wintertime.

At the July 2010 Governing Board meeting, staff presented an Interim Technology Assessment to address the board resolution commitments in 2008. The Interim Technology Assessment summarized the biogas engine control technologies to date and the status of on-going demonstration projects. Due to the delays caused by the permit moratorium in 2009, the release of a subsequent report was recommended upon the completion of these projects. The Interim Technology Assessment concluded that feasible, cost-effective technology should be available that can support the implementation of the July 2012 emission limits, but that the delay in the demonstration projects would likely necessitate an adjustment to the July 1, 2012 compliance date of Rule 1110.2.

The September 2012 amendments established a compliance date of January 1, 2016 for biogas engines. A compliance option was also provided so that operators requiring additional time would be given up to two years beyond the compliance date with the submittal of a compliance plan and payment of a compliance flexibility fee. In addition, SCAQMD staff presented an Assessment of Available Technology for Control of NOx, CO, and VOC Emissions from Biogas-Fueled Engines that detailed the different available technologies and demonstration projects for biogas engines, along with costs.

EXTENSION OF THE COMPLIANCE DATE FOR BIOGAS ENGINES

Since the amendments to Rule 1110.2 on September 7, 2012, SCAQMD staff has met with the stakeholders periodically, both in public forums and through individual meetings for updates on technology implementation. Based on feedback from these operators, some installations will take longer to install than expected and will reach full compliance after the current deadline of January 1, 2016. The range of implementation dates ranged from about mid-2016 to mid-2018.

On March 31, 2011, the Orange County Sanitation District (OCSD) completed a one year pilot study demonstration of biogas cleanup with oxidation catalyst and SCR. Since that time, the system has continued to meet the future limits of the rule and the operator is currently in the process of retrofitting the remaining engines at its two facilities with the same technology. However, since there are a total of seven engines requiring retrofits, the overall project completion date will be after January 1, 2016. Other operators have similar timelines and have expressed their concerns to SCAQMD staff about meeting the January 1, 2016 deadline.

Two biogas technology demonstration projects are continuing. One is the NOxTech system at Eastern Municipal Water District's Temecula plant. NOxTech utilizes selective non-catalytic reduction (SNCR) without the necessity for fuel gas pretreatment. Although some preliminary data has shown that the system is capable of reducing NOx from digester gas fueled engines down to 11 ppm, consistent performance is still being fine-tuned by the facility. Based on the results of additional testing of this unit, the technology may also be installed at another facility that operates one digester gas engine.

The second technology demonstration project is the hydrogen assisted lean operation (HALO) with partial oxidation gas turbine (POGT) at the City of San Bernardino Municipal Water Department. This technology employs hydrogen enrichment of the digester gas that results in leaner operation of the engine, reducing NOx emissions. The project has been partially funded with money from the SCAQMD along with the state. The project was awarded to the Gas Technology Institute (GTI) for fabrication and installation. The fabrication and installation has experienced some setbacks which have resulted in delays of the delivery of essential components belonging to the new system. The City of San Bernardino is hoping to use the results of this demonstration project, which will be utilized for only one engine, to possibly retrofit the remaining engines at the facility, five in total. Given the setbacks and delays, the operators feel that they will have a difficult time implementing the technology by 2018.

Based on the feedback from the regulated facility operators, SCAQMD staff is proposing to extend the compliance deadline for biogas engines beyond January 1, 2016.

EPA'S RULING ON EXCESS EMISSIONS DUE TO BREAKDOWNS

According to EPA Region IX staff, the current Rule 1110.2 language suggests that sources might be protected from enforcement for even gross emission violations during preventable breakdowns. Under this assessment, the current rule language is not consistent with national policy as described in EPA's recent supplemental notice of proposed rulemaking on excess emissions from startup, shutdown, and malfunction (SSM) on 79 FR 55920 (9/17/2014). This final action was finalized on June 12, 2015 (80 FR 33840). The inconsistent Rule 1110.2 language originated in the February 2, 2008 adopted amendment and EPA Region IX's comments refer to this language in the July 9, 2010 amendment. The inconsistency of the rule language with EPA national policy and its final action precludes its ability to fully approve the rule~~ and regulation~~. In the final action, EPA states that its policy applies to:

> "Entities potentially affected by this action include states, U.S. territories, local authorities and eligible tribes that are currently administering, or may in the future administer, EPA-approved implementation plans ("air agencies")."

Amendments are proposed to Rule 1110.2 to resolve EPA's issue with potential gross emission violations during ~~preventable~~ breakdowns. Failure to resolve this issue will result in EPA's disapproval of the 2010 <u>or the current proposed</u> amendment into the State Implementation Plan (SIP). If this disapproval is finalized, sanctions would be imposed unless the U.S. EPA approves subsequent SIP revisions that correct the rule deficiencies within 18 months of disapproval.

A final disapproval would also trigger the two-year clock for the Federal Implementation Plan (FIP) requirement. It should be noted that the submitted rule has been adopted by the SCAQMD, and U.S. EPA's final disapproval would not prevent the SCAQMD from enforcing it.

KEY ISSUES

From ongoing meetings with the affected stakeholders in the Biogas Technology Advisory Committee, staff has summarized key issues that have resulted from those discussions.

1. *The Need for Additional Time to Comply*. Most of the stakeholders notified SCAQMD staff that they would need more time beyond January 1, 2016. Particularly, operators of biogas engine demonstration projects have encountered delays and operational issues that would also necessitate additional time to resolve. One operator stated that they will need even more time to comply than is being proposed.

2. *Complying with EPA's Breakdown Provisions*. SCAQMD staff has received feedback from the regulated community that points to concerns with complying with both SCAQMD rules and EPA's SSM policy. Industry representatives have requested alternative rule language which would remove rule language stating that breakdowns are not violations, thus subjecting operators to potential federal enforcement action or citizen lawsuits.

AFFECTED INDUSTRIES

Rule 1110.2 applies to stationary and portable reciprocating internal combustion engines (ICEs) over 50 brake horsepower (bhp). PAR 1110.2 also affects the subset of engines that are fueled with biogas, which are those that are operated by landfills and wastewater treatment plants. Biogas engines are typically lean-burn engines that operate similarly to lean-burn natural gas-fired engines with a higher level of exhaust oxygen.

Despite past efforts to reduce emissions, biogas-fueled engines remain the dirtiest in terms an emission rate of mass per unit of power produced in the Basin, even though they are fired with renewable fuel. Even at BACT, these engines pollute significantly more than large central generating stations on a pound per megawatt-hour basis (Figure 2). Central generating stations are subject to the CARB 2007 Distributed Generation standards. For current biogas ICEs, the NOx emissions are over 25 times higher than those of central power plants, 119 times higher for VOC, and 75 times higher for CO.

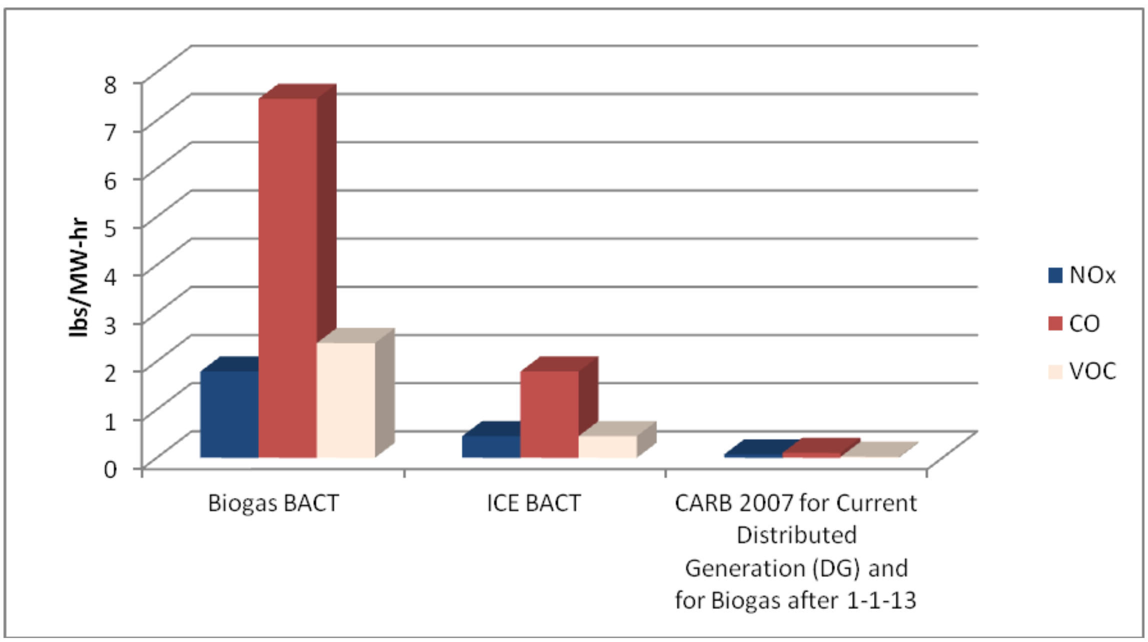

Figure 2. Current BACT for Biogas ICEs and Natural Gas ICEs vs. Central Generating Station BACT

During the 2010 Interim Technology Assessment, approximately 66 engines fueled by biogas were identified. Since that time, however, the number has decreased to 58 due to some engines being placed out of service. Nonetheless, the remaining biogas engines in operation are among the top NOx emitters amongst stationary, non-emergency engines.

For the proposed amendments pertaining to EPA's concerns over equipment breakdowns and excess emissions, these requirements would apply to all operators of gaseous- and liquid-fueled engines governed by this rule.

PUBLIC PROCESS

Since the 2008 amendment, staff has held numerous meetings of the Biogas Technology Advisory Committee with representatives from affected facilities, manufacturers, consultants and other interested parties. The Biogas Technology Advisory Committee was part of the ongoing commitment to finalize the Technology Assessment for biogas engines. Since the amendments in 2012, the Biogas Technology Advisory Committee has met on:

October 29, 2013,
May 28, 2014,
October 29, 2014,
January 14, 2015,
and February 19, 2015.

The Air and Waste Management Association (A&WMA) hosted a biogas workshop at the SCAQMD on May 16, 2013, where information on implementation technologies was presented. Additionally, the Stationary Source Committee was presented with updates on the implementation of the rule and demonstration projects as directed by the adopting resolution for the 2012 amendment, which required updates to the Stationary Source Committee at least yearly after the 2012 amendments. The Committee heard updates on Rule 1110.2 on:

June 21, 2013,
June 20, 2014,
and January 21, 2015.

SCAQMD's Technology Advancement Office also held two meetings on July 9, 2014 and January 14, 2015 to provide training on a biogas toolkit cost estimator for biogas cleanup projects. This was based on a nationwide survey of biogas control vendors and installations that was performed by a contractor that was awarded the project by SCAQMD.

A task force meeting was held on April 23, 2015 to introduce the proposed amendments and a working group meeting was held on July 9, 2015 where SCAQMD staff presented preliminary rule language for the proposed amendments. The public workshop was held on July 29, 2015 and three more working group meetings were held on August 18, 2015, September 15, 2015, and October 27, 2015.

Staff has also held several meetings with control equipment vendors and also manufacturers of emerging technologies that may provide an alternative to electrical power generation by traditional internal combustion methods. In addition, staff has met individually with nearly every biogas facility operator to discuss site-specific issues, technologies, long-term plans for existing biogas engines, and costs. Several site visits have been conducted by SCAQMD staff at affected facilities.

CHAPTER 2: SUMMARY OF PROPOSED RULE 1110.2

PROPOSED AMENDED RULE REQUIREMENTS

PROPOSED AMENDED RULE REQUIREMENTS

The key proposed amendments can be summarized as follows:

- Extend the effective date for compliance to January 1, 2017 for all biogas engines.
- Extend the effective date for compliance to January 1, 2018 for demonstration project biogas engine operators.
- Provide an alternate compliance option to provide operators additional time for engine retrofits beyond the proposed compliance date with the submittal of a compliance plan and payment of a compliance flexibility fee.
    - Up to January 1, 2019 for demonstration projects
    - Up to January 1, 2018 for all other biogas engines
- The compliance flexibility fee would be allowed to be paid in quarterly increments, up to one year beyond the applicable compliance date.
- To address EPA's concerns on breakdowns and potential excess emissions without enforcement, staff is proposing that within any calendar quarter a facility operator would be allowed up to three incidences of breakdown per quarter~~engine~~ of NOx emissions that exceed 45 ppmv for lean burn engines and 150 ppmv for rich burn engines. For CO emissions, no more than three incidences of breakdown per quarter would be allowed that are above 250 ppmv for lean burn engines and 2000 for rich burn engines.
- An alternative rule proposal has been included that would remove rule language stating that breakdowns are not violations, thus subjecting operators to potential federal enforcement action or citizen lawsuits.
- For biogas engines operating until the time of compliance with the limits specified in Table III-B, the emission thresholds for breakdowns that will count towards the incidence limit are 185 ppmv for NOx and 2000 ppmv for CO.
- Diagnostic emission checks would be subject to the current rule provisions for correcting and demonstrating compliance within 24 hours from the time the operator knew of the excess emissions. There is no per calendar quarter limit proposed if emissions are below excess emission thresholds for breakdowns.
- Clarifications to Inspection and Monitoring requirements have been made which improve readability and enforcement.

To provide the additional time needed for technology implementation, District staff is proposing to allow biogas engine operators more time for compliance with the emission limits adopted in the 2012 amendment. Subparagraph 1110.2(d)(1)(C) establishes the emission standards for biogas engines, specifies the effective dates for the emission limits, and provides the compliance schedule for all biogas engines, as listed in Table 3 on the next page. The table is split into two parts: The first part reflects the currently effective limits and the second part establishes the one year delay of the effective date limits for compliance.

Table 3. Proposed Concentration Limits for Biogas Engines

CONCENTRATION LIMITS FOR LANDFILL AND DIGESTER GAS (BIOGAS)-FIRED ENGINES		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 36 x ECF[3] bhp < 500: 45 x ECF[3]	Landfill Gas: 40 Digester Gas: 250 x ECF[3]	2000
CONCENTRATION LIMITS EFFECTIVE JANUARY 1, 2017		
NOx (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250

1 Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

2 Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

3 ECF is the efficiency correction factor.

For operators of biogas engine demonstration projects, the compliance date will be extended to January 1, 2018. A new subparagraph (d)(1)(F) will specify the operators referenced previously who are still undergoing demonstration projects.

> "For the City of San Bernardino, Orange County Sanitation District and Eastern Municipal Water District that commenced and implemented technology demonstration projects prior to January 1, 2015, all their biogas engines shall have until January 1, 2018 to comply with the requirements of Table III-B."

The January 1, 2017 (non-demonstration project biogas engines) and January 1, 2018 (demonstration project biogas engines) compliance dates referenced above would involve no fee payment for the additional time.

An alternate compliance option is also proposed to provide biogas operators with additional time to comply beyond the compliance dates referenced in proposed Table III-B and subparagraph (d)(1)(F). The additional time would be provided with the submittal of a compliance plan and compliance flexibility fee. Subdivision (h) outlines the requirements for the plan submittal and the calculation of the compliance flexibility fee. The fee will now be available to be paid in quarterly increments, up to one additional year. Some stakeholders felt that paying for an entire year of fees was excessive, especially if an engine would come into compliance earlier in the year. The fee would now be calculated based on the updated fee rate ($11.75/bhp per quarter) multiplied by the rated brake horsepower of the unit and multiplied by the number of quarters to defer (up to four quarters, or one year). The fees collected from this alternate compliance option will applied to AQMD NOx reduction programs. The proposed amendments will provide biogas engine facilities with additional time to implement the proper controls to meet the emission limits. For non-demonstration project biogas engines, additional time would be provided beyond the January 1, 2017 compliance date in Table III-B up to January 1, 2018 with payment of the fee. For demonstration project biogas engines designated in (d)(1)(F), additional time would be provided beyond the January 1, 2018 compliance date in (d)(1)(F) up to January 1, 2019 with payment of the fee.

The Inspection and Monitoring (I&M) Plan requirements were established in the 2008 amendment to ensure non-CEMS engine compliance with the rule limits between source tests. It includes procedures for the monitoring of engine parameters and periodic testing of emissions with a portable analyzer, as well as recordkeeping requirements. The I&M Plan provisions in subparagraph (f)(1)(D) have been modified for this rule amendment. Subparagraph (f)(1)(D) has been renamed Inspection and Monitoring (I&M) Requirements. The ten clauses in this subparagraph have been reduced to four and they are as follows.

i. I&M Plan requirements which now refer to Attachment 1, including requirements for plan revisions.
ii. Diagnostic emission check requirements.
iii. Requirements for breakdowns with incidence limit (3 strikes provision).
iv. Applicability for engines with CO CEMS only.

All of the existing requirements that list procedures for inclusion into the facility I&M Plan are now in Attachment 1. These requirements also include procedures for diagnostic emission checks and for breakdowns that refer back to the rule provisions in subparagraph (f)(1)(D). References to provisions within Attachment 1 are specified. The requirements in clause (i) clarify that one application is required for each facility that does not have a NOx and CO CEMS for each engine. Furthermore, upon written approval from the Executive Officer~~,~~ the I&M Plan must be implemented. Before any change in I&M Plan operations can be implemented, or when there is a change in emission limits or control equipment, a plan revision must be submitted.

Clause (ii) outlines the diagnostic check requirements. Emission checks performed with a portable analyzer will now be described as diagnostic emission checks. These are unchanged from the existing rule language. A clarification has been made, however, that as long as any oxygen sensor set point adjustments have not been made within 72 hours of the next regularly scheduled diagnostic emission check, an operator can still maintain a monthly (or every 750 hour) testing schedule if the engine is in compliance before and after the set point adjustments. However, if the set points are adjusted within 72 hours of the next regularly scheduled diagnostic emission check, then the engine must revert back to a weekly (or every 150 hour) testing schedule. Subclause (f)(1)(D)(ii)(IV) states that no engine or control system maintenance or tuning may occur within 72 hours prior to the diagnostic emission check, unless it is an unscheduled, required repair. This clarification requires more frequent testing despite what is stated in subclause (IV) in order to prevent operators from maintaining a less frequent testing schedule if the engine is in compliance before and after the set point adjustments conducted within those 72 hours.

Clause (iii) outlines the procedures for responding to, diagnosing, and correcting breakdowns, faults, malfunctions, alarms, emission checks finding emissions in excess of rule or permit limits, and parameters out-of-range. The staff proposal maintains the 24-hour (or end of an operating cycle) time frame for an owner or operator who uses a portable analyzer as a diagnostic tool for monitoring purposes to correct an exceedance as soon as possible from when it is discovered [subclause (f)(1)(D)(iii)(I)]. If the emissions exceedance is not the result of a breakdown, the operator shall not be considered in violation of the emission limits if the problem is corrected and a subsequent diagnostic emission check demonstrates compliance. To address EPA's issues relating to unenforceable excess emissions from breakdowns, however, the provisions in subclause (II) of clause (iii) outline an incidence limit of no more than three breakdowns per calendar quarter which are above the following emission levels in Table VIII.

TABLE VIII

Excess Emission Concentration Thresholds for Breakdowns

	NO_x (ppmvd)[1]	CO (ppmvd)[1]
Lean-Burn Engines	45	250
Rich-Burn Engines	150	2000
Biogas Engines[2]	185	2000

1 Corrected to 15% oxygen.

2 Effective up to the time of compliance with the limits specified in Table III-B, after which the thresholds revert to the applicable lean- or rich-burn engine limits.

The proposed rule language states,

> "For excess emissions due to breakdowns that result in NOx or CO emissions greater than the concentrations specified in Table VIII, the operator shall not be considered in violation of this rule if the operator demonstrates the following: (1) compliance with subclause (f)(1)(D)(iii)(I), (2) compliance with the reporting requirements of subparagraph (f)(1)(H), and (3) the engine with excess emissions has no more than three incidences of breakdowns with emissions exceeding Table VIII limits in the calendar quarter."

If there are four or more breakdowns within a calendar quarter that do not meet the requirements stated above, it will be a violation. For breakdowns resulting in emissions in excess of the rule or permit limits, the emissions often are of a more serious nature and the staff proposal aims to place a cap on the number of these excursions. EPA's concerns on excess emissions are based on the current rule allowing for correction of a breakdown without penalty and this situation could potentially occur repeatedly, resulting in much more excess emissions. The staff proposal will characterize breakdowns as a new definition in paragraph (c)(3):

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

Further clarification of a breakdown is specified in paragraph (c)(3) in that any breakdown, no matter what the resultant excess emissions would be, that is caused by operator neglect, improper operation or improper maintenance procedures would be a violation. All breakdowns, no matter what the cause, are still subject to the current reporting requirements of Rule 1110.2 (f)(1)(H).

The requirements for parameters out of range that are now in a new subclause (f)(1)(D)(iii)(III). The subclause language would remain unchanged in the proposed rule, except for the addition of the term diagnostic emission check for clarification.

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

Stakeholders have commented on situations where an engine shuts off and a diagnostic emission check cannot be conducted. The staff proposal maintains that if emissions during a breakdown are not verifiable by SCAQMD compliance staff, it will be counted towards the quarterly incidence limit. Stakeholders have asked for more clarity on what qualifies as a breakdown. There are instances where a parameter will go out of range which can result in an engine fault that automatically shuts down the engine before an emissions measurement can be recorded. Another example is if an engine experiences a mechanical fault, such as a blown gasket, which causes it to shut down before an emissions measurement can be taken. For these instances, the onus is on the operator to demonstrate that the parameter drift or mechanical failure was caused by a breakdown that was out of the operator's control and for which excess emissions defined by Table VIII were unlikely. A breakdown that SCAQMD compliance staff verifies the excess emissions being a result of operator error, neglect, improper operation or improper maintenance procedures will count as a violation. Unexpected engine and control system failures occur occasionally and as long as the operator can demonstrate and SCAQMD compliance staff can verify that the cause was not operator error, neglect, improper operation or improper maintenance procedures, then it is a breakdown and operators can have up to three such instances per calendar quarter before becoming a violation. Proposed subclause (f)(1)(D)(iii)(IV) lists existing provisions for parameters out of range that require the operator to correct the problem and demonstrate compliance with another diagnostic emission check within 48 hours of discovery.

Industry representatives have expressed that they would like alternative rule language to be drafted that would also satisfy EPA policy requirements. Subparagraph (f)(1)(H) lists the reporting requirements for breakdowns, which are based on the requirements in SCAQMD Rule 430, Breakdown Provisions. Subclause (f)(1)(D)(v)(III) of the current rule states that an operator shall not be in violation of the emission limits of this rule or in permit conditions if the operator corrects the problem and tests within 24 hours from discovery and complies with the reporting requirements of subparagraph (f)(1)(H). Industry would like the current rule language stating that breakdowns are not violations to be removed. The removal of the language that states "that it is not a violation" <u>in addition to adding suggested clarifying language </u>would satisfy EPA's concerns. However, this would not shield these operators from potential federal enforcement and citizen lawsuits, because Rule 430 is not SIP approved.

The provisions in clause (f)(1)(D)(v) of the current rule would now be in clause (f)(1)(D)(iii). Additional language has been added that states that nothing in clause (f)(1)(D)(iii) is intended to exempt any breakdown that otherwise becomes a violation of local, State, and federal requirements. Under this proposal, a breakdown that SCAQMD staff verifies as not being in violation under Rule 430 would still not be exempt from federal enforcement. In the event that stakeholders request amending the rule at a later time to something less stringent, such as the provision in the current staff proposal, it may not be approvable by EPA because it would constitute a backsliding from what was originally amended.

~~Industry maintains that it would like to proceed with this proposal, so s~~<u>S</u>taff is proposing two versions of the proposed rule for Governing Board consideration:

1. Staff proposal with breakdown emission thresholds and quarterly incidence limit, and

2. Industry-suggested– proposal that would remove rule language stating that breakdowns are not violations, thus subjecting operators to potential federal enforcement action or citizen lawsuits.

Minor clarifications were also added to further specify the requirements of the I&M Plan for engines that operate with CEMS. An engine that operates both NOx and CO CEMS is not subject to the requirements of subparagraph (f)(1)(D), which contain the I&M Plan requirements. Operators with engines that have CEMS have the advantage of monitoring their emissions continuously and would be instantly alerted in the event that something goes wrong with the equipment. Any excess of the emission standard for these engines would be a violation under the current rule. There are, however, engines that have a NOx CEMS but do not have a CO CEMS. For example, lean-burn engines typically have inherently lower CO emissions than their rich-burn counterparts and are not required to have a CO CEMS as stated in clause (f)(1)(A)(vii) of the current rule. Since these engines have a NOx CEMS, an I&M Plan as it pertains to NOx is not required. However, since these engines are subject to the quarterly CO monitoring requirements of (f)(1)(D)(iii)(II) in the current rule as part of the I&M Plan, proposed clause (f)(1)(D)(iv) clarifies the applicability of these requirements for CO.

> "If an engine has a NOx CEMS and does not have a CO CEMS, it is subject to this subparagraph (f)(1)(D) as it pertains to CO only."

CHAPTER 3: IMPACT ASSESSMENT

EMISSIONS IMPACTS AND COST EFFECTIVENESS

INCREMENTAL COST EFFECTIVENESS

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA) ANALYSIS

SOCIOECONOMIC ASSESSMENT

DRAFT FINDINGS UNDER CALIFORNIA HEALTH & SAFETY CODE SECTION 40727

COMPARATIVE ANALYSIS

EMISSIONS IMPACTS AND COST EFFECTIVENESS

The proposed amendments will have emissions impacts on biogas engines regulated by Rule 1110.2, but they would be delayed. Since biogas engines emit significantly more pollutants than natural gas engines and central power plants, the future emission standard will reduce NOx, VOC, and CO emissions significantly. On an aggregate pollutant basis, current biogas engine emission rates per megawatt-hour are over 55 times higher than those of central power plants. The future emission standard will result in up to 74% emission reductions from current biogas ICE emissions (Figure 3).

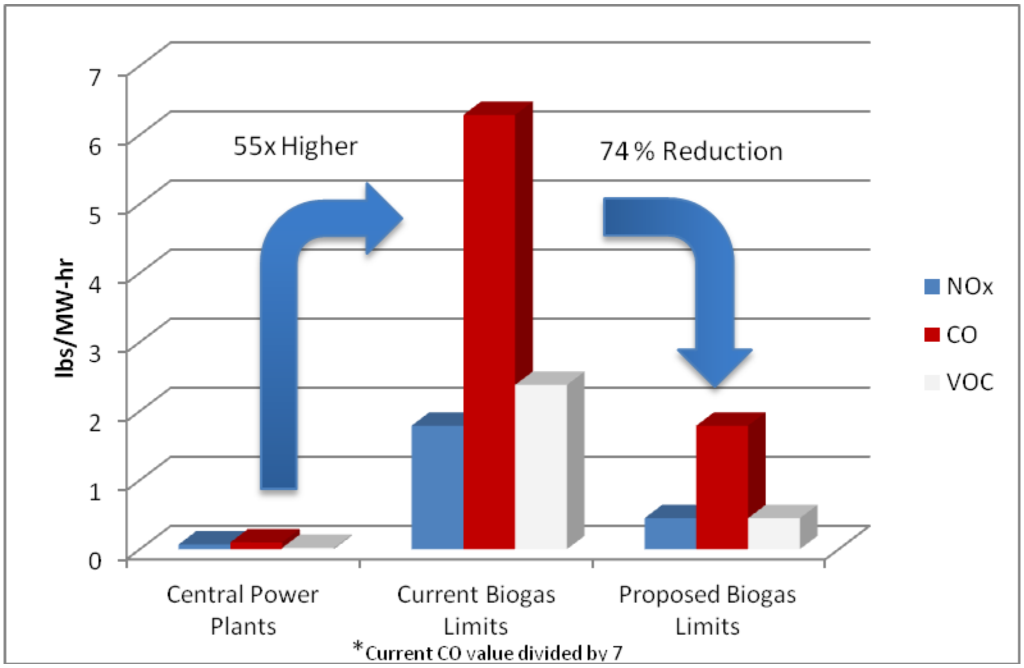

Figure 3. Emissions from Biogas ICEs versus Central Power Plants

The emission reductions calculated during the 2012 amendments were 0.9 tons per day of NOx, 0.5 tons per day of VOC, and 20.0 tons of CO. The reductions under the proposed amendment would occur in two steps. The first reductions will occur by January 1, 2017 and the second step of reductions will occur one to two years later when all biogas engines will comply with the rule limits, including those under the alternate compliance option.

During the 2012 amendment, the cost effectiveness for biogas engines was estimated to range from $1,700 to $3,500 per ton of NOx, VOC, and CO/7 reduced. Staff also calculated cost effectiveness to account for additional gas cleanup and associated contingencies, based on stakeholder feedback. Using vendor quotes for gas cleanup systems, two additional cost effectiveness curves were created reflecting the additional gas cleanup and an added 20% capital cost contingency. The upper cost effectiveness curve has a range from $2,600 to $5,900 per ton. The upper and lower (base level) curves create a band that accounts for equipment contingencies. The cost effectiveness ranges are illustrated in Figure 4 for digester gas engines and Figure 5 for landfill gas engines.

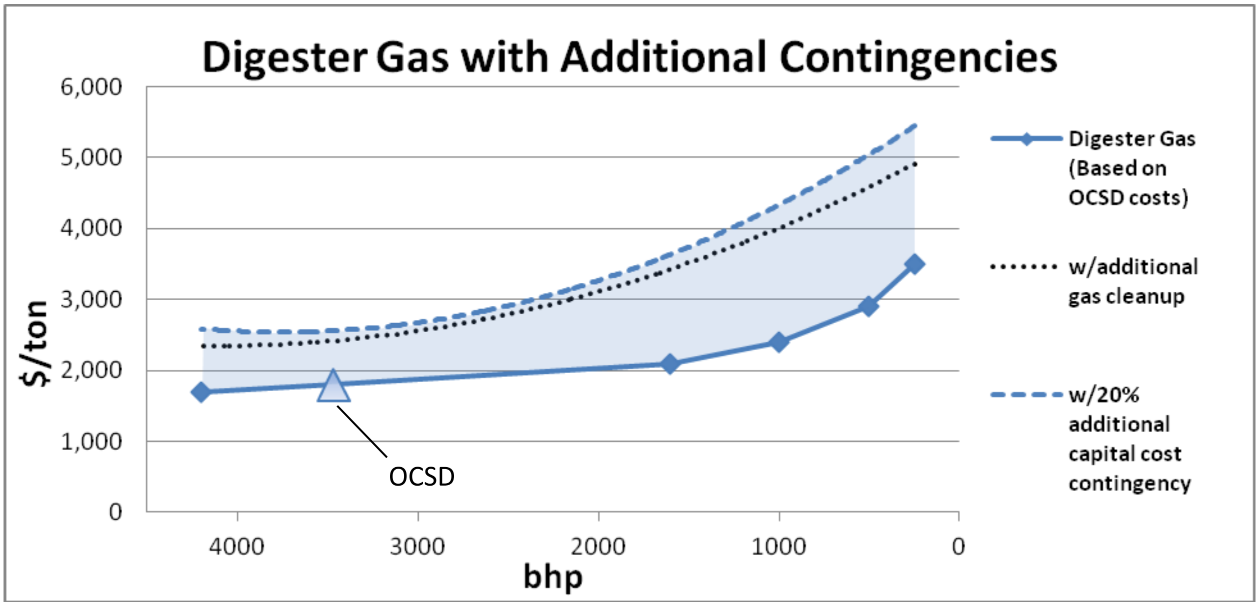

Figure 4. Cost Effectiveness for Digester Gas (Catalytic Aftertreatment)

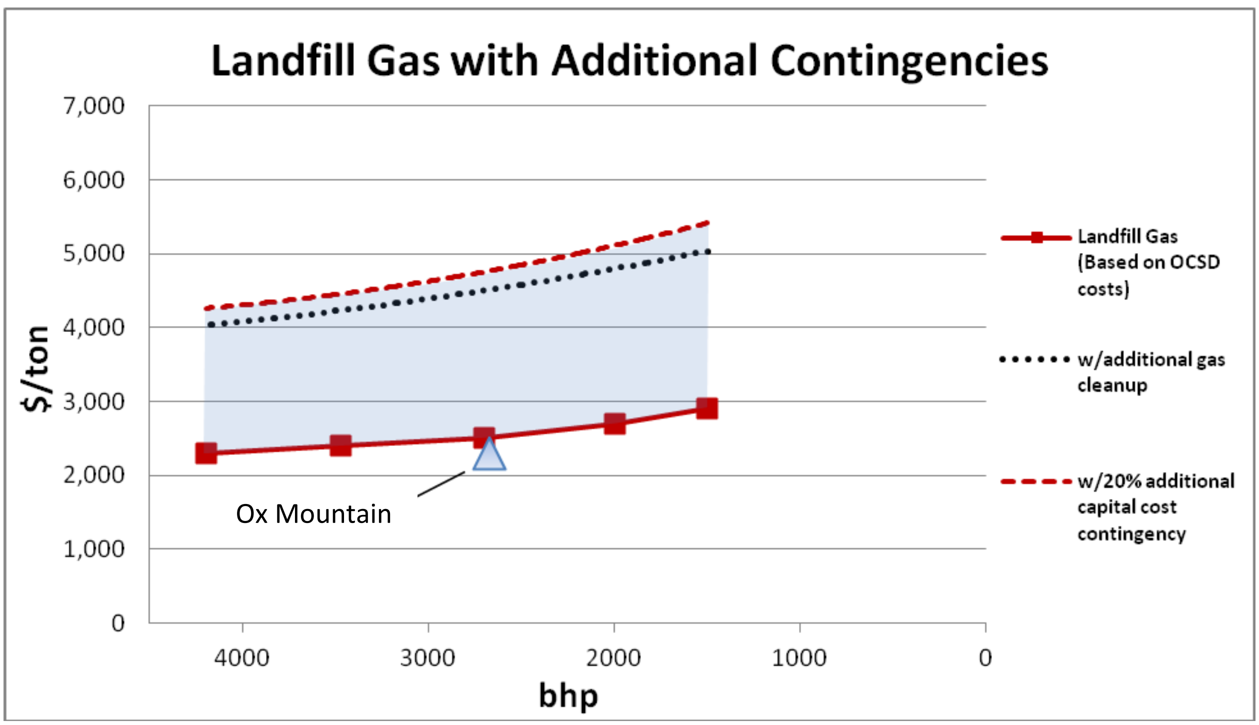

Figure 5. Cost Effectiveness for Landfill Gas (Catalytic Aftertreatment)

Digester gas and landfill gas engines of all sizes were shown to be cost-effective in 2012. The proposed amendments pertaining to EPA's policy on excess emissions from breakdowns will not require the modification or addition of control equipment and will not have an effect on costs.

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 ozone, CO, SOx, NOx, and their precursors. The proposed amendment does not include new BARCT requirements; therefore, this provision does not apply to the proposed amendment.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA) ANALYSIS

PAR 1110.2 is considered a "project" as defined by the California Environmental Quality Act (CEQA), and the SCAQMD is the designated lead agency. Pursuant to CEQA and SCAQMD Rule 110, SCAQMD staff reviewed PAR 1110.2 and concluded that a Subsequent Environmental Assessment (SEA) was the appropriate CEQA document for the proposed project. Staff released a Notice of Preparation and Initial Study (NOP/IS) for a 30-day public review period from July 29, 2015 to August 27, 2015, and a CEQA scoping meeting was held on Thursday, August 13, 2015 at 10 AM in Conference Room GB at SCAQMD Headquarters. No comments were received on the NOP/IS or at the scoping meeting. The Draft SEA was circulated for public review and comment from September 1, 2015 to October 16, 2015. No comments were received on the Draft SEA. Since the close of the comment period, revisions have been proposed to PAR 1110.2. Staff has analyzed these proposed revisions and have determined that they do not trigger recirculation pursuant to CEQA Guidelines §15088.5. The Draft SEA can be obtained at SCAQMD Headquarters, by calling the SCAQMD Public Information Center at (909) 396-3600, or by accessing SCAQMD's CEQA website at: http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2015/par-1110_2-draft-sea.pdf?sfvrsn=2.

SOCIOECONOMIC ASSESSMENT

PAR 1110.2 would delay implementation of new concentration limits for biogas-fired engines at affected facilities from 2016 to between 2017 and 2019. In addition, PAR 1110.2 would affect fewer biogas-fired engines. The additional time for compliance and fewer affected engines would result in potential savings for affected facilities. As such, no adverse socioeconomic impact is anticipated for PAR 1110.2.

DRAFT FINDINGS UNDER CALIFORNIA HEALTH & SAFETY CODE SECTION 40727

California Health and Safety Code Section 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. In order to determine compliance with Sections 40727 and 40727.2 a written analysis is required comparing the proposed rule with existing regulations.

The draft findings are as follows:

Necessity: PAR 1110.2 is necessary to reduce emission limits from combustion equipment in order to meet federal and state ambient air quality standards for ozone and PM 2.5.

Authority: The AQMD obtains its authority to adopt, amend, or repeal rules and regulations from California Health and Safety Code Sections 39002, 40000, 40001, 40440, 40702, 40725 through 40728, and 41508.

Clarity: PAR 1110.2 has been written or displayed so that its meaning can be easily understood by the persons affected by the rule.

Consistency: PAR 1110.2 is in harmony with, and not in conflict with or contradictory to, existing federal or state statutes, court decisions or federal regulations.

Non-Duplication: PAR 1110.2 does not impose the same requirement as any existing state or federal regulation, and is necessary and proper to execute the powers and duties granted to, and imposed upon the AQMD.

Reference: In amending this rule, the following statutes which the AQMD hereby implements, interprets or makes specific are referenced: Health and Safety Code sections 39002, 40001, 40702, 40440(a), and 40725 through 40728.5.

COMPARATIVE ANALYSIS

Under Health and Safety Code Section 40727.2, the AQMD is required to perform a comparative written analysis when adopting, amending, or repealing a rule or regulation. The comparative analysis is relative to existing federal requirements, existing or proposed AQMD rules and air pollution control requirements and guidelines that are applicable to industrial, institutional, and commercial combustion equipment. A comparative analysis is not required if the District finds that the proposed rule does not impose a new emission limit or standard. The District makes that finding, since the 2012 limits are already existing and the proposed rule does not make it more stringent. Nevertheless, the District incorporates by reference the comparative analysis contained in the February 2008 Final Staff Report for PAR 1110.2, which is also updated below for changes.

National Emissions Standards for Hazardous Air Pollutants and New Source Performance Standards

Appendix F in the 2008 Final Staff Report for Proposed Amended Rule 1110.2 (February 2008) provides a detailed summary and comparison of the key elements of PAR 1110.2, the RICE NESHAP, and the NSPS. Appendix F is incorporated in this report by reference and is available at http://www.aqmd.gov/hb/2008/February/080233a.html. The proposed amendments of PAR 1110.2 are not in conflict with federal regulations.

AQMD Rules Applying to Stationary Gaseous- and Liquid-Fueled Engines

AQMD Rule 218 and 218.1 - Continuous Emission Monitoring Rules, which were amended on May 14, 1999, and May 4, 2012, respectively, set forth requirements for new, modified and existing continuous emission monitoring systems that include certification, development and implementation of a Quality Assurance/Quality Control Plan, recordkeeping, reporting, and performance specifications. PAR 1110.2 requires ICEs with required CEMS to comply with Rule 218 and 218.1.

AQMD Rule 401 – Visible Emissions, which was last amended on November 9, 2001, prohibits the discharge of emissions into the atmosphere from any single source for period or periods aggregating more than three minutes in any one hour which will cause: a dark or darker shade as that of a number 1 on the Ringelmann chart, as published by the United States Bureau of Mines, or of an opacity equal or greater than number 1 on the Ringelmann chart.

AQMD Rule 431.1 – Sulfur Content of Gaseous Fuels, which was last amended on June 12, 1998, prohibits the sale and use natural gas with a sulfur content exceeding 16 ppm. Rule 431.1 also prohibits the sale and use of the following gases with a sulfur content exceeding: 150 ppmv in landfill gas; 40 ppmv in refinery gas, sewage digester gas and other gases.

AQMD Rule 431.2 – Sulfur Content of Liquid Fuels, which was last amended on September 15, 2000, prohibits the purchase by stationary source end users of any diesel fuel with a sulfur content exceeding 15 ppm on and after June 1, 2004.

AQMD Rule 1303 - New Source Review Requirements, which was last amended on December 6, 2002, requires BACT, modeling and emission offsets for any new or modified source which results in an emission increase of any nonattainment air contaminant, ozone depleting compound or ammonia.

AQMD Rule 1401 - New Source Review of Toxic Air Contaminants, which was last amended on June 5, 2015, specifies limits for maximum individual cancer risk (MICR), cancer burden, and non-cancer acute and chronic hazard index (HI) from new, modified and existing permitted sources which emit toxic air contaminants (TACs) listed in Table I of Rule 1401. Although numerous TACs may be emitted from engines, formaldehyde, acrolein, methanol, and acetaldehyde account for essentially all of the mass emissions. PAR 1110.2 target pollutants are NOx, VOC and CO.

AQMD Rule 1470 - Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines, which was amended on May 4, 2012, addresses primarily toxic diesel PM from new and existing, stationary, emergency and non-emergency, diesel engines, whereas Rule 1110.2 addresses only NOx, VOC and CO emissions.

AQMD Regulation XX - Regional Clean Air Incentive Market (RECLAIM) superseded many Regulation IV and Regulation XI rules for NOx and SOx for the largest facilities with an emission trading program that achieved equivalent emission reductions, but in a way to allow facilities flexibility in achieving emission reduction requirements for NOx and SOx by methods such as add-on controls, equipment modifications, reformulated products, operational changes, shutdowns, and the purchase of excess emission reductions. Facilities for which emission fee data for 1990 or subsequent year shows four or more tons per year of NOx or SOx, excluding certain exempt sources, are subject to this program. Regulation XX specifically identifies requirements for ICEs, in addition to other specific sources, which include monitoring, reporting and recordkeeping for NOx and SOx emissions. PAR 1110.2 would apply to VOC and CO emissions from IC Engines from these sources.

While only applicable to new electrical generating engines, the CARB 2007 Distributed Generation Regulation is discussed below.

CARB 2007 Distributed Generation Regulation

Beginning in 2007 CARB required new Distributed Generation (DG) units sold in the state to be certified by meeting emission standards that are at least equivalent or more stringent than those for large central power generating stations with BACT. The emission standards are applicable unless engines are subject to District requirements. In addition, the regulation calls for currently permitted equipment to meet the more stringent emission standard by the earliest practicable date. Biogas fueled ICEs subject to the CARB regulation installed after January 1, 2013 must meet the emission standards of large central power generating stations with BACT.

ATTACHMENT A

PAR 1110.2 PUBLIC COMMENTS AND RESPONSES

The Public Workshop for Proposed Amended Rule 1110.2 was held on July 29, 2015. Comment letters received on and after that date are responded to below. These comments helped the rule proposal evolve, and staff appreciates all the stakeholder input.

The 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	Fortistar Methane Group LLC letter dated August 10, 2015
Comment Letter #2	Eastern Municipal Water District letter dated August 13, 2015
Comment Letter #3	Southern California Alliance of Publicly Owned Treatment Works (SCAP) letter dated August 14, 2015
Comment Letter #4	California Council for Environmental and Economic Balance (CCEEB) letter dated August 17, 2015
Comment Letter #5	Karl Lany/Montrose Environmental email dated August 18, 2015
Comment Letter #6	SoCalGas letter dated August 19, 2015
Comment Letter #7	Mesa Water District letter dated October 7, 2015
Comment Letter #8	Southern California Association of Publicly Owned Treatment Works, Eastern Municipal Water District, Small Business Alliance, Southern California Gas Company, Southern California Air Quality Alliance, Western States Petroleum Association, Orange County Sanitation District, Los Angeles County Sanitation Districts, Irvine Ranch Water District, City of Corona, Department of Water and Power, City of Riverside Public Works Department, City of San Bernardino Municipal Water Department, Inland Empire Utilities Agency, South Orange County Wastewater Authority, California Independent Petroleum Association, California Association of Sanitation Agencies, Regulatory Flexibility Group, Waste Management letter dated October 15, 2015
Comment Letter #9	CCEEB letter dated October 19, 2015
Comment Letter #10	Fortistar Methane Group LLC letter dated October 27, 2015

Comment Letter #1 – Fortistar Methane Group LLC, August 10, 2015

FORTISTAR METHANE GROUP LLC
One North Lexington Avenue • White Plains, New York 10601
Tel. (914) 421-4900 • Fax. (914) 421-0052

August 10, 2015

BY US POST

Mr. Mark Abromowitz
Board Consultant to Hon. Joseph Lyou
South Coast AQMD

Dear Mr. Abromowitz:

On behalf of Fortistar Methane Group LLC ("Fortistar") please accept this comment letter in conjunction with the rule-making process for SCAQMD Rule 1110.2 ("Rule"). As you know, Fortistar has been an active participant in the Rule 1110.2 "Working Group" and we appreciate the Board's collaborative approach relative to the proposed changes to the Rule.

At the July 2015 Working Group meeting, a draft set of proposed Rule changes were distributed which carve out additional time for compliance to two specific entities – the City of San Bernardino and the Eastern Municipal Water District. We greatly appreciated staff's decision to propose an additional compliance timeframe for these entities based on their early exploration and adoption of technology demonstration projects. We respectfully request that Fortistar and its associated sites subject to the Rule be considered for the same extension based on a similar level of investment and commitment to future compliance with the Rule. 1-1

Please know that after reviewing the course of events, it is clear that we have fallen short in sharing with staff the efforts we have taken which would justify such an extension, and are appreciative of your consideration of the information below which includes a description of our sites, our negotiations with equipment suppliers and economic considerations that we feel support our request. 1-2

1. **Overview of Fortistar Sites**

Six of Fortistar's project entities are affected by the pending implementation Rule 1110.2. They are:

1. MM Lopez Energy LLC - (Los Angeles County)
2. MM Prima Desheca Energy LLC- (Orange County)
3. Coyote Canyon Energy LLC – (Orange County) 1-3
4. NM Milliken Genco LLC – (San Bernardino County)
5. NM Mid Valley Genco LLC - (San Bernardino County)
6. NM Colton LLC – (San Bernardino County)

Of these six facilities, four (Milliken, Mid Valley, Coyote Canyon, and Colton) have either recently been shut down or will shortly be shut down for economic reasons unrelated to Rule

1

1110.2. The remaining two facilities, Lopez and Prima continue to operate and are the focus of this briefing.

2. Lopez Facility, Los Angeles County

Currently, Lopez has two functioning engines that deliver energy. Lopez was accepted into the LADWP FIT Program in June 2014. Prior to that, it was clear that the project's power purchase agreement, with a ten-year term beginning in 2006, did not generate sufficient cash flow to support the installation of equipment required by Rule 1110.2.

With Lopez's acceptance into the LADWP FIT program in June 2014, Fortistar became actively engaged, investing in plans and specifications that will result in a fully engineered selective catalytic reduction (SCR) system for one of the two engines[1]. We have attached as Exhibit A our efforts to explore and invest in this technology. We are committed to install this system in 2016. After an appropriate shakeout period, the engine will be fully operational and compliant in 2017. Given this timeframe, and our existing investment in this technology, *we would respectfully request the Lopez project be allowed a compliance extension date of January 1, 2018.*

We believe the facts are clear that Fortistar has expended substantial efforts to employing an SRS Rule 1110.2-compliant system. Fortistar initially invested in the analysis of several alternative technologies and, as described below, in 2014 selected DCL International, Inc. ("DCL) which we determined had the highest probability of reliability. DCL was to build a plant for another party that we could review and was also to provide a guarantee on operations. We have since come to learn that the construction project is delayed and the guarantee is different than from what we initially anticipated. 1-3 cont.

Specifically, Fortistar initiated discussions with equipment suppliers for compliant equipment upgrades in June 2014 including DCL and Airflow Catalyst Systems. Fortistar developed a strong interest in DCL's approach due to DCL's stated ability to provide a firm guarantee that encompassed the entire scope of equipment supply. This single vendor concept is important to Fortistar because procuring gas conditioning equipment and exhaust gas treatment from separate vendors inherently creates more operational and warranty risk should the equipment ultimately fail to provide the gas quality required for our PPA partners. Accordingly, from the beginning of our discussions with DCL we required operational data to confirm the proposed equipment's effectiveness. Unfortunately, for various reasons, DCL has not yet provided the data to Fortistar and the equipment guarantee has not materialized in an acceptable form.

Although we continue to work with DCL in pursuit of data proving the effectiveness of their proposed equipment and warranty, we are now actively working with other vendors to comply with the Rule. For gas conditioning we are in discussions with Parker and Willexa relative to equipment proposals. For the SCR system we are engaged in active discussions with Miratech as an alternative to AeriNOx (a DCL affiliated company). Our first priority, based on engineering, production and delivery constraints, is the procurement of the gas conditioning equipment. We are informed, the expected production timeline for this component is approximately 26 weeks from approved drawings with 4-6 weeks being required for submittal drawing preparation. Allowing 2 weeks to

[1] The second engine is scheduled for shut-down consistent with the implementation date of Rule 1110.2.

2

review/approve drawings, this amounts to approximately 34 weeks to deliver a gas conditioning system.

As you can see from Exhibit A, we have been substantially involved in the vetting of new compliance technologies and have invested resources – financial and otherwise – in exploring all options. Our proposed path forward for Lopez is:

- Continue negotiations with equipment vendors so that a recommendation can be made to Fortistar management for procurement of a gas conditioning system by **8/31/15.**
- Issue purchase order for gas conditioning system on or about **9/30/15** and subject to Fortistar's satisfaction of the reliability of the equipment. 1-3 cont
- Electrical separation of Lopez engines complete and providing power to LADWP by **10/30/15.**
- Continue negotiations with equipment vendors and recommend procurement of an SCR system by **10/30/15.**
- Issue purchase order for SCR system by **1/15/16.**
- Delivery of gas conditioning system at Lopez expected by **6/1/16.**
- System operational for testing following installation by **10/1/16.**
- Lopez gas conditioning system and SCR system fully operational by **1/1/17. Note: Shake out period and reliable functioning by 1/1/18 .**

However, the decision to analyze and deploy new technology does not exist in a vacuum. Like other entities, Fortistar continues to make these decisions against the backdrop of the economic climate in which it operates. This is evident considering our experience at Prima Descheca.

3. Prima Descheca

Although the Lopez site is our test bed for our integration of compliance technologies, economic factors make the Prima Descheca ("Prima") site more challenging. Prima entered into a power purchase agreement (PPA) with SDG&E in 2008 which expires on October 1, 2022. The power pricing is in the high $50/MW-hour range. The low power price and short term remaining on the PPA do not provide for adequate revenue or operating life to recover the installation and operational costs of the necessary equipment for Rule 1110.2 compliance. The project has an annual net profit of approximately $200,000. In addition, the project has posted an approximate $940,000 letter of credit securing its obligation to deliver electricity to SDG&E for the term of the PPA. If required to comply with Rule 1110.2, the project would be forced to shut down effective by January 2017, resulting in an approximate loss of $2,500,000 in revenues, including the loss of the letter of credit. 1-4

Further, with annual Compliance Flexibility Payments estimated at $390,000, these obligations alone are far in excess of annual profits which makes it uneconomic to continue operations. Given these facts, *we believe it is equitable to request that the Prima project be grandfathered under existing rules and be permitted to operate until the expiration of the current term of the SDG&E PPA, or October 1, 2022*.

1-4 cont.

4. Conclusion

We appreciate your consideration of Fortistar's genuine and substantial efforts in adopting compliance technology and the circumstances, which we feel justify an extension of the compliance timelines at two of our facilities. We understand that the rule making process is a complex one and we thank you for your receipt and evaluation of these comments.

Very truly yours,

Jonathan Maurer (ff)

Jonathan Maurer
Acting CEO
Fortistar Methane Group, LLC

4

EXHIBIT A: TIMELINE OF EFFORTS TO COMPLY WITH RULE 1011.2

The following is a timeline of actions taken relative to procurement of equipment necessary for compliance with Rule 1110.2. Many communications with DCL and other vendors have taken place in addition to these events:

- **June 2014** – Acceptance of Fortistar proposal by LADWP for power under the LADWP FIT program. Until this date, Fortistar did not have a viable financial model for installation of equipment required by rule 1110.2. **The project was approved and funded subject to conditions required for financing (i.e. executed PPA). This included the installation of equipment required by rule 1110.2.**
- **September 2014** – Project Development scoping meeting conducted at DCL office in Toronto, Canada.
- **9/16/14** – DCL visits Lopez site and draws gas samples collected for use in development of the preliminary design of the gas conditioning and SCR systems.
- **9/30/14** – Fortistar received quote for gas conditioning and purification system from DCL.
- **10/2/14** – Gas analytical report received from 9/16/14 samples.
- **10/3/14** – Fortistar received quote for catalytic guard bed from DCL.
- **10/31/14** – Fortistar received revised proposal from AeriNOx for SCR system based on ongoing discussions with the vendor.
- **10/31/15** – Fortistar completed development and was in a position to execute PPA with LADWP; we deferred execution to request some contract cleanup items.
- **2/10/15** – Fortistar received a revised quote from DCL for gas conditioning and catalytic guard systems based on ongoing discussions with the vendor. Met with DCL prior to 1110.2 meeting and were told to expect operational data imminently. Fortistar expressed willingness to execute a Purchase Order with DCL once data was reviewed.
- **2/26/15** – Gas sampling for additional VOC data.
- **3/18/15** – Met with DCL in New Orleans and were told to expect operational data imminently.
- **3/31/15** – Fortistar received the cleanup items on the terms of the LADWP PPA and executed the contract.
- **4/9/15** – Receipt of fully executed PPA from LADWP for Lopez project. **It is important to note that this was a requirement for financing of the project.**
- **4/22/15** – Fortistar requested quote from Miratech for SCR system.

5

- **4/29/15** – Fortistar received quote from Miratech for SCR system.
- **6/2/15** – Fortistar received a revised quote for a catalytic guard from DCL based on ongoing discussions with the vendor.
- **6/12/15** – Fortistar received revised quote from Aerinox for SCR system based on ongoing discussions with the vendor.
- **6/19/15** – Updated separate quotes received from DCL and Aerinox. **In spite of initial statements about warranty structure and specific requests from Fortistar for confirmation of the "complete" warranty by DCL, these separate quotes did not provide the warranty that Fortistar anticipated from DCL.**
- **6/24/15** – Proposal received from Willexa for alternative gas conditioning system. Evaluation of the proposal is ongoing.
- **7/1/15** - Fortistar provided comments back to DCL on technical and commercial issues in the 6/19/15 proposal. Negotiations are ongoing.
- **7/2/15** – Fortistar requested quote from Parker for gas conditioning system.
- **7/9/15** – Fortistar's Engineering and Construction Director attended SCAQMD's 1110.2 workshop.
- **7/22/15** – Fortistar met with SCAQMD's permitting staff to review the feasibility of permitting DCL's approach to handling the off-gas.

6

Responses to Letter #1

Response 1-1

SCAQMD appreciates your comment letter submittal for the proposed amendments to Rule 1110.2. The extension of the final compliance date to January 1, 2018 for operators of demonstration projects was provided because these operators, in fact, commenced the demonstration projects several years ago. Demonstration projects may require additional time for the testing and maturation of newer technology to the point that it could be considered achieved in practice. Although Fortistar, through discussions with staff and in the working group meetings, has initiated moving forward with the installation at one of its facilities, it is not a demonstration project and therefore cannot be granted additional time until January 1, 2018 to comply. The rule proposal provides, however, additional time with the payment of a compliance flexibility fee in quarterly increments.

Response 1-2

As stated in the response to comment 1-1, we acknowledge and appreciate the steps that Fortistar has taken to implement the rule requirements at its facilities.

Response 1-3:

SCAQMD staff acknowledges and appreciates the work that Fortistar has done in pursuing the installation of controls at the Lopez facility. As stated in the response to comment 1-1, additional time beyond the January 1, 2017 deadline can be provided upon the payment of a compliance flexibility fee in quarterly increments. The commenter states that more time is needed to ensure reliable functioning during a shake out period. During the rule making for the 2012 amendments to Rule 1110.2, provisions were added that would extend the averaging time for emissions up to a monthly average for the first four months of operation specifically to address and startup issues. This is contingent on the engine achieving a concentration level more than 10% below the rule limits, as proven in other achieved-in-practice installations. After the first four months of startup operation, a 24-hour average can be used if this high level of performance can be achieved.

Response 1-4:

The commenter states that it would be difficult and uneconomic to install controls at the Prima facility because the PPA it had entered into would make it financially difficult to come up with the revenue required for the installation of engine controls. While this may be the case for this facility, staff feels that there should ~~must~~ have been an expectation in 2008 when the PPA was initiated that the engines at that location would be subject to controls. During the rule making for the 2008 amendments to Rule 1110.2, which occurred in 2007, the initial compliance deadline for biogas engines would have been July 1, 2012, contingent on the completion of a technology assessment. Unexpected delays ~~invalidated this compliance date, which~~ resulted in another rule development to re-establish the biogas engine compliance deadline for January 1, 2016. It is the opinion of staff that the operator had full knowledge of future ~~what was coming in terms of a~~ compliance deadlines, and in ~~for~~ the ~~best~~ interest of public health, staff has established the proposed compliance deadline for higher polluting biogas engines.

Comment Letter #2 – Eastern Municipal Water District, August 13, 2015

EASTERN MUNICIPAL
WATER DISTRICT
SINCE 1950

August 13, 2015

Dr. Barry Wallerstein, Executive Officer
South Coast Air Quality
Management District
21865 Copley Drive
Diamond Bar, California
91765

Dear Mr. Wallerstein:

SUBJECT: **Comments on the Proposed Amended Rule 1110.2 Emissions from Gaseous and Liquid-Fueled Engines dated July 29, 2015**

The Eastern Municipal Water District (EMWD) appreciates this opportunity to provide comments on the Proposed Amended Rule 1110.2. EMWD operates 54 prime natural gas engines and four digester gas/dual fuel engines to provide potable water and water reclamation services to 755,000 people in a service area of 542 square miles. As the provider of both water and wastewater reclamation services, EMWD is responsible for effectively managing its resources economically while being a good neighbor to the community. 2-1

Please consider the following comments:

1. EMWD greatly appreciates the South Coast Air Quality Management District (SCAQMD) staff efforts to address our concerns regarding the biogas engine compliance date. EMWD continues to implement demonstration projects and invest our resources to advance new and unproven technology, which we hope will provide cost-effective options for future biogas engine applications.

2. EMWD is concerned with the ranges and limitations for breakdowns and emission checks proposed in Rule 1110.2 (f)(1)(D)(v)(I) thru (V). SCAQMD has adopted the most restrictive air pollution rules in the United States, including a comprehensive breakdown rule and engine inspection and monitoring (I&M) program. Despite this comprehensive compliance program, the proposed language essentially imposes undue increased 2-2

Mailing Address: Post Office Box 8300 Perris, CA 92572-8300 Telephone: (951) 928-3777 Fax: (951) 928-6177
Location: 2270 Trumble Road Perris, CA 92570 Internet: www.emwd.org

Dr. Barry Wallerstein
Page Two
August 13, 2015

> enforcement towards operators in the South Coast Air Basin who have already implemented frequent inspection, monitoring and maintenance of engines as required by the current rule. The impact from the proposed rule may result in financial cost to engine operators due to enforcement actions but will not decrease current emission levels in the basin as breakdowns are usually due to unforeseen problems with engines. In addition, during previous rule amendment discussions, SCAQMD staff observed and acknowledged that the air-to-fuel ratio is crucial for maintaining compliance and that there are limitations with stationary technology in which there is signal drift for unknown reasons and that oxygen sensor response can diminish over time. As discussed in the 2008 Rule 1110.2 staff report, the I&M program which includes frequent diagnostic emission checks, was added to the rule to identify and address emission problems in between source tests. Recognizing the limitations of the available technology for stationary engines, it is our understanding that these diagnostic emission checks were not intended to be used as enforcement as presented in the proposed rule. 2-2 cont.

EMWD is supportive of the biogas engine provisions contained in the Proposed Amended Rule; however EMWD is concerned that the proposed breakdown and emission check provisions will delay the adoption of the revised biogas engine compliance dates. Without these compliance date revisions, EMWD may be unable to operate our biogas engines despite our efforts to achieve the proposed emission limits through demonstration projects. Despite our strong desire to adopt these revisions, we are deeply concerned about the proposed breakdown and emission check provisions. As a result, we respectfully request that the rule revision process be bifurcated to ensure biogas engine provisions can be adopted as planned, while separately assessing the SCAQMD proposed amendments to address EPA's concerns. This approach will allow EMWD to complete our biogas engine demonstration efforts and retrofits, while allowing all stakeholders enough time to carefully assess SCAQMD response to EPA's concerns. 2-3

Thank you in advance for considering our comments above and for the opportunity to comment. If you have any questions, please feel free to contact Al Javier at (951) 928-3777 extension 6327 or at javiera@emwd.org.

Sincerely,

Jayne E. Joy, P.E
Director of Environmental and Regulatory Compliance

JJ/ARJ:tlg

cc:
Dr. Philip Fine, SCAQMD
Jill Whynot, SCAQMD
Joe Cassmassi, SCAQMD
Records Management, EMWD

Responses to Letter #2

Response 2-1:
SCAQMD acknowledges EMWD's commitment to demonstrating new technology and appreciates the effort put forth in reducing emissions from biogas engines.

Response 2-2:
The commenter expresses concern on the staff proposal regarding engine breakdowns and concentration limits proposed for both diagnostic emission checks and for breakdowns that was presented at the July 29, 2015 Public Workshop. Since that time, staff has worked with stakeholders to further refine the rule language. It has proposed concentration thresholds for gross emissions due to breakdowns for rich-burn engines, lean-burn engines, and biogas engines. If a diagnostic emission check finds emissions below these thresholds, it will not count against the quarterly incidence limit of three. The concentration thresholds were based on actual data collected from portable analyzer testing conducted by staff during the 2008 amendments to Rule 1110.2. In addition, staff asked engine operators for data to support these threshold concentration levels. We acknowledge that air-fuel ratio controller drift occurs quite frequently and that these events would not be categorized as breakdowns if the emissions do not exceed the thresholds proposed in the rule. The existing inspection and monitoring provisions in the rule for diagnostic emission checks address signal drift and instances when the oxygen sensors are replaced.

Response 2-3:
The commenter requests a bifurcation of the rule amendments so that the biogas provisions are adopted first, while providing more time to amend the breakdown provisions. Unfortunately, EPA has expressed to staff that not addressing its concerns during this rulemaking will force the limited disapproval of the rule and begin a sanction clock.

Comment Letter #3 – Southern California Alliance of Publicly Owned Treatment Works (SCAP), August 14, 2015

SCAP
SOUTHERN CALIFORNIA ALLIANCE OF PUBLICLY OWNED TREATMENT WORKS

August 14, 2015

Dr. Barry Wallerstein, Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, California 91765

Dear Dr. Wallerstein:

Re: Comments on Proposed Amended Rule 1110.2

The Southern California Alliance of Publicly Owned Treatment Works (SCAP) appreciates this opportunity to provide comments on Proposed Amended Rule 1110.2. SCAP represents 83 public agencies that provide essential water supply and wastewater treatment to nearly 19 million people in Los Angeles, Orange, San Diego, Santa Barbara, Riverside, San Bernardino and Ventura counties. SCAP's wastewater members provide environmentally sound, cost-effective management of more than two billion gallons of wastewater each day and, in the process, convert wastes into resources such as recycled water and renewable energy.

SCAP greatly appreciates the proposed biogas engine compliance date extension. We do have a minor comment regarding the compliance date, which is described below. While we support the revised biogas engine provisions, our members are troubled by the proposed breakdown provisions. We believe this issue stems from EPA's May 22, 2015 SSM SIP Call, and since it has much wider industry ramifications than just the Rule 1110.2 universe of sources, it should be carefully assessed by SCAQMD legal staff and then fully vetted by all impacted sources. Considering the proposed breakdown provisions were first provided to stakeholders on July 9, 2015, SCAP recommends that the rule be bifurcated to ensure the biogas engine provisions can be adopted quickly, while separately and deliberately assessing how best to respond to EPA's evolving SSM policy. 3-1

<u>Biogas Engine Discussion:</u>
SCAP appreciates SCAQMD staff's efforts to address our concerns regarding the biogas engine compliance date. As you are aware, it is challenging to implement new biogas engine technology to 3-2

P.O. Box 231565
Encinitas, CA 92024-1565
Fax: 760-479-4881 Tel: 760-479-4880 Website: www.scap1.org Email: info@scap1.org

Dr. Barry Wallerstein August 14, 2015

achieve the lower emission limits. Our members have expended a tremendous amount of public resources to advance unproven technology, which we hope will provide cost-effective options for future biogas engine applications. While the proposed extension until January 1, 2018 for Eastern Municipal Water District and the City of San Bernardino is absolutely essential, we believe that Orange County Sanitation District (OCSD) should also be specifically identified in the rule. Although OCSD commenced construction on their retrofit project prior to other agencies, large complex projects can experience unforeseen problems. Based upon OCSD's early and good-faith efforts, we request the same extension be afforded to this public agency as well. 3-2 cont.

SSM Breakdown Discussion:
We have been informed that EPA objects to the existing Rule 1110.2 breakdown provisions. To better understand this objection, and because EPA has not provided any written comments, we contacted EPA staff and obtained some useful feedback. EPA confirmed that their concerns regarding the existing breakdown provisions are derived from the SSM litigation and the resulting SIP Call [Federal Register / Vol. 80, No. 113 / June 12, 2015]. This EPA action requires identified states and air districts to submit corrective SIPs by November 22, 2016. However, SCAQMD is not included in this SIP Call.

Based upon our conversations with EPA, we believe that there may be various approaches to address EPA's new SSM policy. In fact, EPA's SIP Call indicates that states and local agencies are allowed to issue their own enforcement discretion criteria, but such criteria cannot be binding on the United States or any citizens group. Unfortunately, EPA didn't provide much guidance explaining how to implement this new policy. In fact, the situation is further complicated by litigation that has been filed further challenging EPA's new SSM policy. What is clear though is that this major national policy is intended to address bad actors in states with weak pollution control requirements. SCAQMD has adopted the most restrictive air pollution rules in the United States, including a comprehensive breakdown rule, so we cannot believe that breakdowns in the South Coast Air Basin could cause significant emissions like those outlined by the Sierra Club's petition to the EPA. Bearing in mind that SCAQMD is not identified in the SIP Call, we believe that we have time to carefully assess EPA's new SSM policy rather than rushing to adopt a rule based solely on verbal feedback from EPA. 3-3

Conclusion:
SCAP is supportive of the biogas engine provisions contained in the proposed amended rule, with a very minor modification. Our members are concerned that the proposed breakdown provisions will side-track the adoption of revised biogas engine compliance dates. Without these revisions, public agencies that have acted in good-faith to achieve the proposed emission limits may be unable to operate their biogas engines. Despite our strong desire to adopt these revisions, we are deeply concerned about the proposed breakdown provisions. As a result, we respectfully request that the rule revision process be bifurcated. This approach will allow our members to complete their biogas engine retrofits, while allowing all stakeholders enough time to carefully assess EPA's new SSM policy. 3-4

2

Dr. Barry Wallerstein August 14, 2015

Thank you for the opportunity to comment on the proposed amended rule. Please do not hesitate to contact Mr. David Rothbart of the Los Angeles County Sanitation Districts should you have any questions at (562) 908-4288, extension 2412.

Sincerely,

John Pastore

John Pastore, Executive Director

cc:

Dr. Philip Fine, SCAQMD
Jill Whynot, SCAQMD
Joe Cassmassi, SCAQMD

3

Responses to Letter #3

Response 3-1:
The commenter expresses concerns regarding the proposed breakdown provisions and requests that the rule be bifurcated to adopt the biogas provisions while separately assessing how to respond to EPA's concerns with breakdowns. Unfortunately, EPA has expressed to staff that not addressing its concerns during this rulemaking will force the limited disapproval of the rule and begin a sanction clock.

Response 3-2:
The comment requests that Orange County Sanitation District (OCSD) also be included among those facilities that implemented demonstration projects, based on its early commencement of technology demonstration, and be given an additional year to comply with the emission requirements without payment of a fee.

Staff has agreed with the comment and will include OCSD in the proposed subparagraph (d)(1)(F) to give this facility the additional time.

Response 3-3:
The comment refers to EPA's startup, shutdown, and malfunction (SSM) litigation and resulting SIP call, which SCAQMD was not a part of. In addition, the commenter states that staff should not rush to adopt a rule based solely on verbal feedback from EPA.

Staff has spoken extensively with EPA on many occasions, beginning early this year on this matter. Although SCAQMD was not a part of the SIP call that the commenter refers to, it faces a limited disapproval of the rule that was amended in 2010 if the breakdown issues are not addressed. Staff has proposed rule language that EPA says will satisfy its concerns in limiting the amount of excess emissions from breakdowns by requiring enforcement action if the proposed quarterly incidence limit is surpassed. Furthermore, EPA's final action which was released on June 12, 2015 is considered binding rulemaking and not simply guidance.

Response 3-4:

This comment duplicates the suggestions expressed in Comments 3-2 and 3-3. See Responses 3-2 and 3-3.

Comment Letter #4 – California Council for Environmental and Economic Balance (CCEEB), August 17, 2015

California Council for Environmental and Economic Balance
101 Mission Street, Suite 1440, San Francisco, California 94105
415-512-7890 phone, 415-512-7897 fax, www.cceeb.org

August 17, 2015

Dr. Philip Fine
Deputy Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, California 91765

RE: Comments on Proposed Amended Rule 1110.2 - Emissions from Gaseous- and Liquid-Fueled Engines

Dear Dr. Fine:

On behalf of the members of the California Council for Environmental and Economic Balance (CCEEB), we wish to provide you with comments on one aspect of Proposed Amended Rule 1110.2 (PAR 1110.2). CCEEB supports the comments of the Southern California Alliance of Publicly Owned Treatment Works (SCAP) in its letter of August 14, 2015 (attached), specifically the request for a bifurcation of the proposal by pulling out proposed changes to the breakdown provisions. While CCEEB has not been active in discussions regarding the specifics of the biogas engine provisions, we too are concerned with the proposed breakdown provisions. 4-1

We understand that the changes to the breakdown provisions are possibly the result of EPA's May 22, 2015 SSM SIP Call. While the provisions as proposed in PAR 1110.2 are a concern, we have further concerns should similar language be added to other rules. If this were to occur, the impact could be quite significant to our members. 4-2

We support SCAP's call for a bifurcation of the proposal. This would allow time for staff to work with all stakeholders who could be impacted by changes to SSM provisions. 4-3

Dr. Philip Fine
August 17, 2015
Page 2

Thank you for considering our views. Please do no hesitate to call me at 415-512-7890, extension 115, should you wish to discuss further,

Sincerely,

William J. Quinn
Vice President and Chief Operating Officer

cc: Jill Whynot
Joe Cassmassi

Responses to Letter #4

Response 4-1:

The comment supports those provided by SCAP in its August 14, 2015 comment letter requesting bifurcation of the proposal by pulling out the proposed changes to the breakdown provisions. As stated in the responses to the comments submitted by SCAP, staff is obligated to comply with EPA's requirements. Otherwise, the SCAQMD will be faced with a limited disapproval of the rule and the start of a sanction clock. Staff feels that the breakdown provisions as proposed are reasonable and will prevent excess emissions from repeated engine breakdowns.

Response 4-2:

The comment states that the proposed breakdown provisions are a result of the May 22, 2015 SIP call and that similar language will be added to other rules. Staff was made aware of the potential limited disapproval of the rule long before the SIP call and has worked with EPA to develop proposed rule language that would make the rule fully approvable. EPA has stated that SCAQMD Rule 430, which is not SIP approved, will be disapproved shortly. For other rules, approvability concerns may be handled individually by rule, or globally with alternatives to Rule 430.

Response 4-3:

The comment duplicates the suggestions expressed in Comment 4-1 and 4-2. See Responses 4-1 and 4-2.

Comment Letter #5 – Karl Lany, Montrose Environmental, August 18, 2015

Kevin Orellana

From: Karl Lany <klany@montrose-env.com>
Sent: Tuesday, August 18, 2015 8:04 PM
To: Joe Cassmassi
Cc: Philip Fine; Kevin Orellana; Gary Quinn
Subject: Proposed Rule 1110.2
Attachments: Karl Lany.vcf

Hello Mr. Cassmassi,

Please excuse my communication via email, rather than a more formal letter regarding proposed Amended Rule 1110.2.

I was greatly encouraged by SCAQMD's revised strategy for dealing with excess emissions that may be observed during 150 hr and 750 hr monitoring events, and I thank SCAQMD for giving consideration to the concepts presented by the regulated community during the July 29th workshop . The language initially proposed on July 29 present unreasonable consequences for operators and ignore the mutual understanding of both SCAQMD and the regulated community that served as the foundation of the monitoring program. 5-1

I look forward to seeing SCAQMD's revised proposal, but in the meantime I offer the following comments that I hope you will take into consideration as you finalize rule language:

Definitions

Because SCAQMD's new proposal introduces the term "diagnostic emissions check", it seems appropriate to incorporate a definition of the term into the rule. Based upon today's presentation, I understand that the provision that would excuse exceedances from the three occurrence limit is intended to apply to the 150 hr and 750 hr monitoring events. It should also apply to other voluntary checks such as those that may occur during engine maintenance and tune-up operations. Existing language, however, refers to the 150 hr and 750 hr monitoring events as "emissions checks" and by introducing the word "diagnostic" SCAQMD may lead one to incorrectly assume that the provisions you are proposing apply to maintenance activities, but not the 150 hr and 750 hr monitoring events or other voluntary actions. 5-2

Three Occurrence Standard

During today's meeting, SCAQMD indicated that the three occurrence standard would apply to any combination of NOx and CO excursions. I question if such an interpretation is indeed reasonable. It seems that once an engine's performance starts to drift from optimal conditions, steps taken by the operator to correct for one pollutant can lead to an excursion of another pollutant and if such corrective action requires intervention for more than just a single day, the three occurrence threshold may be more likely to be crossed simply due to those corrective actions. I suggest that the three occurrence threshold should be applied independently to each pollutant. 5-3

Thank you for considering these comments. I am happy to discuss if you like.

MONTROSE ENVIRONMENTAL

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

Responses to Letter #5

Response 5-1

The commenter is greatly encouraged at the revised strategy for dealing with excess emissions observed during diagnostic emission checks subsequent to the Public Workshop. Staff appreciates the comment and is pleased that the dialogue with the regulated community has resulted in favorable results.

Response 5-2

The comment recommends a definition for the term “diagnostic emission check” to differentiate between testing done due to monitoring and testing done for maintenance activities. As proposed, the rule would excuse exceedances from the three occurrence limit for diagnostic emission checks, but it should also apply to other voluntary checks such as maintenance operations.

The use of the term diagnostic emission check is used for consistency between other combustion rules, primarily Rules 1146 and 1146.1 for boilers. Diagnostic emission checks are performed for a variety of reasons, inclusive of those that the commenter has pointed out. They are performed to both verify compliant operation and to ensure that emission exceedances are resolved. Staff feels that a definition is not necessary. Staff would also like to clarify the comment that excuses emission exceedances from the three occurrence limit for diagnostic emission checks. If a diagnostic emission check (whether conducted as part of periodic monitoring or maintenance) finds emissions under the thresholds listed in the proposed rule, then it does not count against the incidence limit. However, if a diagnostic emission check finds emissions above the proposed thresholds and it is determined to be caused by a breakdown, it will need to be reported as a breakdown event to the SCAQMD. If SCAQMD enforcement staff determines that the event occurred within the control of the operator, then it will be an automatic violation. If SCAQMD enforcement staff determines that the event occurred outside the control of the operator, then it will count against the per calendar quarter incidence limit. A definition of breakdown has been included as part of the proposed amendments.

Response 5-3

The commenter suggests that the proposed breakdown per calendar quarter incidence limit should apply independently to each pollutant because corrective action taken for one pollutant can lead to an excursion of the other, especially if the corrective action takes more than one day. The rule language proposes breakdown provisions per incident for any combination of pollutants. If corrective action results in exceedant diagnostic emission checks for another pollutant, the obligation is on the operator to demonstrate to SCAQMD enforcement staff that the exceedant readings can be attributed to the same incident.

Comment Letter #6 – SoCalGas, August 19, 2015

SoCalGas comment letter
August 19, 2015

SoCalGas
A Sempra Energy utility

Daniel R. McGivney
Environmental Affairs Program Manager
Energy and Environmental Affairs

1981 W. Lugonia Ave., SC8013
Redlands, California 92374-9796

tel: 951-225-2958
email: dmcgivney@semprautilities.com

August 19, 2015

Mr. Joseph Cassmassi
Planning & Rules Director
South Coast Air Quality Management District
21865 East Copley Drive
Diamond Bar, CA 91765

VIA EMAIL: jcassmassi@aqmd.gov

RE: South Coast Air Quality Management District Proposed Amended Rule 1110.2

Dear Mr. Cassmassi:

The Southern California Gas Company (SoCalGas) appreciates this opportunity to provide comments regarding the South Coast Air Quality Management District's (District) proposed amendments to Rule 1110.2 (PAR 1110.2) which regulate emissions from gaseous and liquid fueled engines. The comments that follow are based upon the District's July 29, 2015 draft PAR 1110.2 and associated draft Staff Report.

The proposed amendments are focused in two areas: amendments to provide additional time for biogas fueled engines to attain emission limits specified in section (d)(1)(C) and amendments affecting section (f)(1)(D)(v) regarding breakdown and emission check procedures. SoCalGas' comments are focused on the later proposed amendments. 6-1

In various meetings and discussions with District staff beginning in early July, it is SoCalGas' understanding that the proposed amendments regarding the breakdown provisions are in response to concerns expressed by the United States Environmental Protection Agency (EPA) in regard to Rule 1110.2 State Implementation Plan (SIP) approvability affected by a recent court case decision [*NRDC v. EPA*, 749 F.3d 1055 (D.C. Cir. 2014)] affecting EPA's Start-up, Shut-down and Malfunctions (SSM) policy, resulting in the ensuing May 22, 2015 SIP Call [Federal Register Volume 80, Number 113 (Friday, June 12, 2015)]. SoCalGas has also discussed the proposed revision with EPA staff and understands that there is currently no schedule or deadline associated with this issue and that EPA is open to any justifiable solution. It is also SoCalGas' understanding that this issue may affect a much broader range of equipment/sources. 6-2

1

SoCalGas comment letter
August 19, 2015

Considering the potentially broad impact of the SSM issue upon regulated entities and equipment, and the particular complexity of Rule 1110.2, SoCalGas formally requests that the District bifurcate these proposed amendments, adopting the biogas related amendments on the current schedule and deferring any amendments regarding breakdowns/emission checks and SSM policy until a later date such that District staff and affected industry can work together to both better understand the specific issue(s) that EPA has with Rule 1110.2 (as it is SoCalGas' understanding that only verbal communication between EPA and the District has occurred to date) and identify possible approaches that could resolve the issue(s). 6-3

SoCalGas looks forward to continuing this dialog and a mutually favorable resolution of this issue. Again, SoCalGas formally requests that the biogas and breakdown/SSM related amendments be bifurcated into separate rulemaking activities, with the breakdown/SSM amendment process postponed to a later date. Should there be any questions, please contact me at 951-255-2958 or at dmcgivney@semprautilities.com. Thank you for consideration of this request.

Sincerely,

Daniel R. McGivney

Daniel R. McGivney
Environmental Affairs Program Manager
Energy and Environmental Affairs

cc: Philip Fine, Ph.D., SCAQMD
Jill Whynot, SCAQMD

2

Responses to Letter #6

Response 6-1

This introductory comment explains that this comment letter was submitted based on the Preliminary Draft Staff Report and rule language made available on July 29, 2015. Thus, responses to the specific comments are presented in Responses 6-2 and 6-3.

Response 6-2

The comment makes reference to EPA's court decision and SIP call as the reason for the proposed breakdown provisions. The commenter states that it has discussed the proposed rule revision with EPA staff and understands that there is currently no schedule or deadline associated with this issue and that EPA is open to any justifiable solution. In addition, this issue may affect other equipment and sources under SCAQMD rules.

Staff disagrees with the statement that there is no schedule or deadline regarding the proposed amendments. EPA had explicitly expressed to staff that if this rule is amended without addressing the excess emissions related to an uncapped number of breakdowns, the rule will not be approved, which will result in the triggering of a sanction clock. The proposed amendments for biogas engines are necessary to extend the compliance deadline from January 1, 2016 to January 1, 2017, so if the breakdown provisions are not addressed, then there will be a limited disapproval for this rule which is highly undesirable. EPA is open to any justifiable solution and is in agreement with the staff proposal that places a cap on the number of breakdowns per calendar quarter and the associated excess emissions. EPA is also in agreement with the Industry proposal which would subject operators to federal enforcement for breakdowns and would result in an approvable rule. The Industry proposal does not offer any protection from Federal enforcement and citizen lawsuits for excess emissions from breakdowns. EPA has stated that Rule 430 is not SIP approvable~~ed~~ and an official statement will be forthcoming. In the meantime, EPA has addressed enforceability issues on a per rule basis.

Response 6-3

The commenter requests a bifurcation of the proposed amendments, adopting the biogas provisions on the current schedule and deferring the breakdown provisions until a later date since EPA and SCAQMD's verbal communications are the only justification for addressing the breakdown provisions.

As stated in the responses to the comments submitted by SCAP and CCEEB, staff is obligated to comply with EPA's requirements. Otherwise, the SCAQMD will be faced with a limited disapproval of the rule and the start of a sanction clock. EPA's final action which was released on June 12, 2015 is considered binding rulemaking and is not simply guidance. Staff feels that the breakdown provisions as proposed are reasonable and will prevent excess emissions from repeated engine breakdowns, which will result in a SIP-approvable rule.

Comment Letter #7 – Mesa Water District, October 7, 2015

MesaWater DISTRICT

Dedicated to Satisfying our Community's Water Needs

1965 Placentia Avenue
Costa Mesa, CA 92627
Tel 949.631.1200
Fax 949.574.1036
info@MesaWater.org
MesaWater.org

October 7, 2015

Kevin Orellana
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Subject: Comments to Proposed Amended Rule (PAR) – Rule 1110.2 Mesa Water District

Dear Mr. Orellana,

Mesa Water District (Mesa Water®) is a special district that provides water service to 108,000 customers in an 18 square-mile area. Mesa Water® serves most of Costa Mesa, parts of Newport Beach, and some unincorporated areas of Orange County, including the John Wayne Airport.

Mesa Water® relies on internal combustion engines for the distribution of drinking water in the service area. These engines, which support the critical infrastructure for water distribution, are subject to South Coast Air Quality Management District (SCAQMD) Rule 1110.2. Mesa Water® understands that the SCAQMD is in the process of revising certain portions of Rule 1110.2 and is currently seeking comments from the stakeholders in the rule amending process. Mesa Water® is submitting this comment letter to address our concerns on the Proposed Amended Rule (PAR) 1110.2. 7-1

In order to respond to the United States Environmental Protection Agency (USEPA) Startup, Shutdown, and Malfunction (SSM) policy, the SCAQMD is seeking comments from the stakeholders to address the breakdown procedures. Mesa Water® understands that an engine that deviates from the Rule 1110.2 emission limits or permit conditions should not continue operating as a result of a breakdown. Currently, Rule 1110.2 allows an engine to continue operating after a failed portable analyzer emission check for 24 hours or by the end of the operating cycle, whichever comes sooner. The SCAQMD is considering adding provisions in the rule to discourage engine operators from continuing operation if an engine violates emission limits. This will impact Mesa Water's® ability to provide reliable water service to its customers as Mesa Water® diversifies its energy sources for emergency purposes. Mesa Water®'s reservoirs and some well sites are powered by natural gas engines. 7-2

In order to address the Rule 1110.2 breakdown policy, on September 15, 2015, at the Rule 1110.2 Working Committee Group Meeting, SCAQMD staff proposed the following: 7-3

MesaWater DISTRICT®

Dedicated to Satisfying our Community's Water Needs

1965 Placentia Avenue
Costa Mesa, CA 92627
Tel 949.631.1200
Fax 949.574.1036
info@MesaWater.org
MesaWater.org

- *If a diagnostic emission check finds excess emissions that are the result of a breakdown, then it will count as a breakdown and it will need to be reported to the SCAQMD*
- *A breakdown is deemed valid by SCAQMD compliance staff if the facility has proven that it occurred beyond its control*
    - *Will not count as a strike*
- *A breakdown that is not verifiable by SCAQMD compliance staff or a breakdown where emissions cannot be measured or quantified will be counted as a strike*

Mesa Water® would like to comment on the third bullet item above, which states that a breakdown that cannot be verified by SCAQMD compliance staff or a breakdown where emissions cannot be measured or quantified will be counted as a strike.

Mesa Water® would like to request SCAQMD Executive Staff consider revising the third bullet item to remove the language that states when emissions cannot be measured or quantified, it will be counted as a **strike**. For example, if an incident occurs outside of Mesa Water's® normal business hours, a portable analyzer emission check may be delayed and not completed within the timeframe required to comply with the provision of the breakdown rule.

7-3 cont.

Each engine operated by Mesa Water® has an automatic shutdown feature installed that will shut down an engine if there is a potential for severe damage associated with faults or alarms. Common engine shutdown faults or alarms are a high catalyst inlet temperature alarm, an ignition fault, intake manifold pressure, and fuel system failure. The purpose of this fail-safe control mechanism is to prevent the engine from operating when it could lead to catastrophic failures. As a result of the shut down due to possible detrimental engine failure, there will not be an opportunity to perform a portable analyzer test. Under the proposed rule, the incident can easily be counted as a strike for that quarter which is unreasonable. Allowing an engine to continue operating following a fault or an alarm may be catastrophic to the engine. Thus Mesa Water® strongly feels that the proposed language should exclude incidents that could lead to potential catastrophic engine failure. The following language revision is proposed:

- *A breakdown that is not verifiable by SCAQMD compliance staff ~~or a breakdown where emissions cannot be measured or quantified~~ will be counted as a strike*

Mesa Water® would also like to request SCAQMD Executive Staff provide a definition for **verifiable breakdown incident**. Mesa Water® feels that a definition identifying the assessment method, metrics, quantity, etc. will provide clarity in maintaining compliance.

7-4

MesaWater
DISTRICT®

Dedicated to Satisfying our Community's Water Needs

1965 Placentia Avenue
Costa Mesa, CA 92627
Tel 949.631.1200
Fax 949.574.1036
info@MesaWater.org
MesaWater.org

7-5

Additionally, Mesa Water® would like to request SCAQMD Executive Staff add a definition for a **diagnostic emission check** for clarity. Rule 1110.2 specifies a frequency of weekly/monthly (or every 150/750 hours) for portable analyzer emission checks. Mesa Water® performs diagnostic emission checks following an Air-to-Fuel Ratio Controller (AFRC) alarm, parameter out of range, or other deviations. It appears that the SCAQMD is proposing to replace the current language for "portable analyzer emission check" to "diagnostic emission check." For such reason, Mesa Water® believes that adding a definition for a proposed diagnostic emission check will provide clarity in the rule.

Please feel free to contact Kaying Lee, Water Quality and Compliance Supervisor, at (949) 207-5491 if there are further questions.

Sincerely,

Phil Lauri

Phil Lauri
Assistant General Manager
Mesa Water District

cc: Paul Shoenberger, General Manager
Tracy Manning, Assistant Water Operations Manager
District File

Responses to Letter #7

Response 7-1

This introductory comment explains that this comment letter was submitted based on the proposed amendments to Rule 1110.2. Thus, responses to the specific comments are presented in Responses 7-2 through 7-5.

Response 7-2

The commenter is responding to SCAQMD's request for comments from stakeholders regarding EPA's startup, shutdown, and malfunction (SSM) policy. Currently, Rule 1110.2 allows an engine to continue operating after a failed portable analyzer emission check for 24 hours or by the end of the operating cycle, whichever is sooner. The commenter adds that SCAQMD's proposed provisions discourage engine operators from continuing operation if an engine~~s~~ violates emission limits, which impacts the commenter's ability to provide reliable water to its customers.

Staff disagrees with this interpretation that the SCAQMD allows engines to operate in violation of emission limits. The proposed rule language states that in the event of a breakdown, the operator shall correct the problem as soon as possible and demonstrate compliance, or shut down an engine by the end of the operating cycle, or within 24 hours, whichever is sooner. The intent is to prevent engines that are out of compliance to continue to emit excess emissions of pollutants into the air. Staff believes it is in the best interest of an engine operator to fix a problem that is causing the excess emissions, instead of continuing to operate a defective engine which could lead to even further damage to the unit in addition to those excess emissions. The provisions that the commenter is referring to is existing language from the 2008 amendments which place a limit in the amount of time that an engine can continue to operate in the event of a breakdown or diagnostic emission check which finds emissions in exceedance of the rule or permit limits.

Response 7-3

The comment refers to bullet items presented at the September 15, 2015 working group meeting. Specifically, the commenter expresses concern over the point that breakdowns that cannot be measured or determined will be counted as a strike. The commenter provides example of instances where an incident occurs outside of normal business hours where a diagnostic emission check cannot be conducted, as well as engine faults that preventatively shut down an engine to prevent further damage.

As explained in the draft staff report, for these instances the onus is on the operator to demonstrate that the parameter drift or mechanical failure was caused by something other than a breakdown and that it was out of the operator's control. If it is a breakdown, as now defined in the rule proposal definition, and SCAQMD compliance staff verifies that it was not the result of operator error, neglect, improper operation or improper maintenance procedures, it will count against the quarterly incidence limit. There are provisions in the existing rule for parameters out of range, as the commenter had pointed out, where the operator can correct the problem and demonstrate compliance with a diagnostic emission check within 48 hours of the operator first knowing of the problem. Unexpected engine and control system failures occur occasionally and as long as the operator can demonstrate and SCAQMD compliance staff can verify that the cause was not operator error, neglect, improper operation or improper maintenance procedures, then it is a breakdown and not subject to violation as long as the per quarter incidence limit is not exceeded.

Response 7-4

The commenter requests a definition for verifiable breakdown incident to provide clarity in maintaining compliance. The existing provisions in SCAQMD rules already provide this clarity. Subparagraph (f)(1)(H) of the existing rule language lists the reporting requirements for breakdowns. These are based on the existing requirements listed in Rule 430, Breakdown Provisions, which the operator must also comply with. For a breakdown incident SCAQMD enforcement staff promptly investigates the site to determine whether an occurrence meets all SCAQMD criteria to qualify as a breakdown.

Response 7-5

The commenter requests a definition for a diagnostic emission check for clarity between emission checks for used for routine monitoring and for parameter deviations. The use of the term diagnostic emission check is used for consistency between other combustion rules, primarily Rules 1146 and 1146.1 for boilers. Diagnostic emission checks are performed for a variety of reasons, inclusive of those that the commenter has pointed out. They are performed to both verify compliant operation and to ensure that emission exceedances are resolved. Staff feels that a definition is not necessary.

Comment Letter #8 – Southern California Association of Publicly Owned Treatment Works, Eastern Municipal Water District, Small Business Alliance, Southern California Gas Company, Southern California Air Quality Alliance, Western States Petroleum Association, Orange County Sanitation District, Los Angeles County Sanitation Districts, Irvine Ranch Water District, City of Corona, Department of Water and Power, City of Riverside Public Works Department, City of San Bernardino Municipal Water Department, Inland Empire Utilities Agency, South Orange County Wastewater Authority, California Independent Petroleum Association, California Association of Sanitation Agencies, Regulatory Flexibility Group, Waste Management, October 15, 2015

Southern California Association of Publicly Owned Treatment Works, Eastern Municipal Water District, Small Business Alliance, Southern California Gas Company, Southern California Air Quality Alliance, Western States Petroleum Association, Orange County Sanitation District, Los Angeles County Sanitation Districts, Irvine Ranch Water District, City of Corona, Department of Water and Power, City of Riverside Public Works Department, City of San Bernardino Municipal Water Department, Inland Empire Utilities Agency, South Orange County Wastewater Authority, California Independent Petroleum Association, California Association of Sanitation Agencies, Regulatory Flexibility Group, Waste Management

October 15, 2015

Dr. Philip Fine, Deputy Executive Officer
Planning, Rules Development & Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, California 91765

Dear Dr. Fine:

Comments on Proposed Amended Rule 1110.2 –
<u>Sections Related to Breakdowns/Malfunctions</u>

We appreciate this opportunity to provide comments on Proposed Amended Rule 1110.2. Our coalition fully supports SCAQMD Governing Board's adoption of the proposed biogas amendments allowing the affected parties additional time to come into compliance with this rule. However, we are concerned about the proposed changes to the breakdown provisions. While seemingly benign in the context of Rule 1110.2, it is our opinion that they represent a fundamental change in SCAQMD enforcement policy by potentially altering how breakdowns are handled for all industries, especially industries that currently utilize Rule 430. Because of these widespread implications, we respectfully request that the rule be bifurcated to facilitate the approval of proposed biogas provisions, while allowing time for a thorough assessment of the policy issues, especially in light of EPA's new and evolving startup, shutdown, and malfunction (SSM) policy. 8-1

We understand that SCAQMD staff is proposing changes to the Rule 1110.2 breakdown provisions, in response to EPA's concerns about the July 9, 2010 amended version of Rule 1110.2, which was submitted for SIP approval in 2014. EPA believes that the existing breakdown provisions are inconsistent with new national SSM policy, and would prevent full approval of the rule. More specifically, these concerns stem from EPA's new and evolving SSM policy published in the Federal Register, Vol, 80, No. 113 on June 12, 2015 (36-State SIP Call). SCAQMD staff presented the proposed amended breakdown language on July 9, 2015 at a Rule 1110.2 Public Workshop, which was predominantly attended by biogas engine operators. In effect, the proposed breakdown provisions would establish a new SCAQMD SSM policy that could reach far beyond Rule 1110.2 and be applicable to any equipment operating during a SSM event. 8-2

Document Number: 3483889

Dr. Philip Fine -2- October 15, 2015

As stated, we believe it is premature to proceed with the proposed Rule 1110.2 breakdown provisions until the general policy implications are vetted with all impacted industries. Also, we believe that it is premature to establish a new SCAQMD SSM policy because of two pending appellate court petitions that could affect EPA's national SSM policy: (1) August 11, 2015, U.S. Court of Appeals for the District of Columbia Circuit, Case No. 15-1267 filed by 17 states claiming that "*...EPA erroneously concluded that the following State's EPA approved State Implementation Plans are 'substantially inadequate' with respect to periods of startup, shutdown and malfunction and must be revised.*", and (2), July 8, 2015, U.S. Court of Appeals for the Fifth Circuit, Case No. 15-60424 filed by the State of Texas requesting "*...that the Court review those parts of EPA's Final Rule that apply to the State of Texas, including...four provisions in Texas's approved State Implementation Plan..., which provide affirmative defenses for certain upset events, unplanned events, and opacity events...*" The EPA SSM policy being challenged, itself rose from court challenges by environmental groups. Clearly, EPA's new policy has yet to withstand some significant legal challenges which, if successful by the plaintiffs, will once again alter EPA's SSM national policy. 8-3

In addition to the legal challenges facing EPA's new SSM policy, the policy itself is rather nebulous and is subject to interpretation. For example, "*...The EPA emphasizes that there are other approaches that would be consistent with CAA requirements for SIP provisions that states can use to address emissions during SSM events. While automatic exemptions and director's discretion exemptions from otherwise applicable emission limitations are not consistent with the CAA, SIPs may include criteria and procedures for the use of enforcement discretion by air agency personnel.*" At minimum, there is a tremendous amount of flexibility provided to the states. 8-4

In addition, we believe that the proposed breakdown language may be inconsistent with the intent of EPA's new SSM policy outlined in the June 12 Federal Register posting. EPA's policy explains that states and air districts must maintain EPA's authority to enforce and allow citizen suits. The policy calls for SIP revisions to remove deficient provisions, including "*...enforcement discretion provisions that have the effect of barring enforcement by the EPA or through a citizen suit and affirmative defense provisions that are inconsistent with CAA requirements...*" Proposed amended rule language contains provisions that, in our opinion, may not comply with the intent of EPA's policy. 8-5

As outlined, there are significant uncertainties in EPA's national SSM policy due to litigation and policy interpretation difficulties, and any changes to SCAQMD SSM policies are going to impact most industries. In addition, SCAQMD was not included in EPA's 36-State SIP Call. Therefore, rather than rushing to resolve EPA's potential objections at this time, we respectfully request that staff: (1) perform a thorough legal review and analysis of EPA's new policy; (2) assess the validity of pending litigation; and (3) convene a working group to discuss what direction SCAQMD's staff should take on its SSM policy approach. 8-6

Also, we understand that SCAQMD staff would like to provide the Governing Board an EPA approvable rule. However, we believe bifurcation of the rule, so the new biogas engine amendments can be adopted, would be the most prudent approach. We also believe that all options should be kept open, so in the spirit of cooperation, we could support the deletion and modification of the objectionable language, as identified by EPA. Specifically, we recommend modifying paragraph (f)(1)(D)(v)(III) of the rule as follows: 8-7

Dr. Philip Fine -3- October 15, 2015

*"An operator ~~shall not be considered~~ in violation of the emission limits of the rule or in permit conditions**, due to a breakdown or malfunction,** ~~if the operator~~ **shall** compl**y**~~ies~~ with ~~this subparagraph and the reporting requirements of~~ subparagraph (f)(1)(H). Any emission check conducted by the District staff that finds excess emissions is a violation."*

8-7 cont.

We believe such a modification directly addresses the intent of EPA's SSM policy. There are other changes that would be needed to ensure consistency throughout the rule with this approach, but these changes could be worked out quickly. At your earliest convenience, we would like to meet with you and your staff to discuss this proposal, as well as the bifurcation approach.

Thank you for the opportunity to comment on the proposed amended rule. If you have any questions regarding our concerns or recommendations, please do not hesitate to contact David Rothbart at (562) 908-4288, extension 2412.

Sincerely,

David Rothbart, P.E.
Air Quality Committee Chair
Southern California Association of
Publicly Owned Treatment Works
(562) 908-4288, ext. 2412

Bill LaMarr
Executive Director
Small Business Alliance
(714) 778-0763

Curt Coleman
Executive Director
Southern California Air Quality Alliance
(310) 348-8186

Jim Colston
Environmental Compliance Manager
Orange County Sanitation District
(714) 593-7450

Edward Filadelfia
Regulatory Affairs and Compliance Manager
City of Riverside Public Works Department
(951) 351-6080

Paul D. Jones II, P.E.
General Manager
Eastern Municipal Water District
(951) 928-3777

Daniel R. McGivney
Environmental Affairs Program Manager
Energy & Environmental Affairs
Southern California Gas Company
(909) 335-7793

Sue Gornick
Senior Coordinator, Southern CA Region
Western States Petroleum Association
(310) 808-2146

Frank Caponi
Division Engineer
Los Angeles County Sanitation Districts
(562) 908-4288

Paul A. Cook
General Manager
Irvine Ranch Water District
Irvine, CA 92619-7000
(949) 453-5300

Mike Carroll
Latham & Watkins LLP for
Regulatory Flexibility Group
(714) 755-8105

Randy Beck
Director of Operations
WM Renewable Energy, LLC
Waste Management
(713) 265-1672

Sylvie Lee, P.E.
Manager of Planning and Environmental Resources
Inland Empire Utilities Agency
(909) 993-1600

Jonathan Daly
General Manager
City of Corona, Department of Water and Power
(951) 736-2477

Stacey R. Aldstadt
General Manager
City of San Bernardino
Municipal Water Department
(909) 384-5091

Betty Burnett
General Manager
South Orange County Wastewater Authority
(949) 234-5419

Rock Zierman
Chief Executive Officer
California Independent Petroleum Association
(916) 447-1177

Greg Kester
California Association of Sanitation Agencies
Director of Renewable Resource Programs
(916) 446-0388

Responses to Letter #8

Response 8-1

The comment offers support for the adoption of the biogas amendments, but expresses concerns regarding the proposed changes to the breakdown provisions and requests a bifurcation of the rule to facilitate the approval of proposed biogas provisions, while allowing more time to assess EPA's startup, shutdown, and malfunction (SSM) policy.

Staff appreciates the support for the proposed amendments for biogas engine operators. As stated in the responses to the comments submitted by SCAP, CCEEB, and SoCalGas, staff is obligated to comply with EPA's requirements. Otherwise, the SCAQMD will be faced with a limited disapproval of the rule and the start of a sanction clock. EPA's final action which was released on June 12, 2015 is considered binding rulemaking and is not simply guidance. Staff feels that the breakdown provisions as proposed are reasonable and will prevent excess emissions from repeated engine breakdowns, which will result in a SIP-approvable rule.

Response 8-2

The comment refers to the EPA's SSM policy published in the Federal Register on June 12, 2015 that would prevent full approval of Rule 1110.2 and suggests that the SCAQMD will develop a new SSM policy that could reach far beyond Rule 1110.2 and be applicable to any equipment operating during an SSM event.

SCAQMD, for this rule amendment as it pertains to breakdowns, is addressing a recommendation made by EPA to fix areas within the rule that would be disapproved if not addressed. A similar action was taken for Rules 1146 and 1146.1 to prevent the disapproval of those rules. Rule 430, which is currently not SIP-approved, is pending disapproval, according to EPA. As stated in the previous response, staff feels that the breakdown provisions as proposed are reasonable.

Response 8-3

The comment states that because the SSM policy is being challenged legally, it is premature to establish policy with this rule. As stated in the response to Comment 8-1, staff is obligated to respond to EPA's recommendation, despite legal challenges to the SSM policy, because it is binding rulemaking.

Response 8-4

The comment suggests that there is flexibility provided to states in addressing SSM policy. Staff feels that the proposed breakdown provisions are very reasonable and, more importantly, are in agreement with EPA policy.

Response 8-5

The comment suggests that the proposed breakdown provisions do not comply with the intent of EPA policy of removing deficient provisions including enforcement discretion provisions that appear to bar enforcement by EPA or citizens and affirmative defense provisions that are inconsistent with the Clean Air Act or the SSM policy.

Staff disagrees with the commenter's statement. The proposed breakdown provisions satisfy EPA's SSM policy and, furthermore, do not offer enforcement discretion that bars enforcement by EPA or citizens. The proposed language additionally does not provide affirmative defense for operators since there is a cap on the number of breakdown incidents that can occur per calendar quarter and allows for enforcement action if a breakdown is not verifiable.

Response 8-6

The comment states that SCAQMD was not part of EPA's 36-state SIP call and requests that staff performs a thorough legal review and analysis of EPA's SSM policy, assess the validity of pending litigation, and convene a working group to discuss what direction SCAQMD staff should take on its SSM approach.

Although SCAQMD was not explicitly part of the 36-state SIP call, SCAQMD was directed by EPA to correct the rule language that was not consistent with the SSM policy. The SIP call specifically stated that

> "Entities potentially affected by this action include states, U.S. territories, local authorities and eligible tribes that are currently administering, or may in the future administer, EPA-approved implementation plans ("air agencies")."

~~Otherwise, a~~As stated in the response to Comment 8-1, the SCAQMD will be faced with a limited disapproval of the rule and the start of a sanction clock. EPA and SCAQMD have been in discussion regarding this issue since the beginning of this year and despite pending litigation, the SSM policy is binding rulemaking. Please refer to Responses 8-1 and 8-3.

Response 8-7

The comment reiterates the request for the bifurcation of the rule so that the new biogas amendments can be adopted. However, the commenter has offered suggested rule language that would be supported by EPA. The rule language deletes the phrasing that states that an operator shall not be considered in violation if a breakdown incident is corrected and reported.

Staff appreciates the cooperation of Industry and has proposed to provide two versions of the rule for consideration by the Governing Board. The first version is the staff proposal, while the second is the industry proposal which would not provide relief from federal enforcement action if an operator reports a breakdown. As a result, this second version would not shield an operator from federal enforcement and citizen lawsuits since every breakdown would be a federal violation, since Rule 430 is not SIP-approved.

Comment Letter #9 – California Council for Environmental and Economic Balance (CCEEB), October 19, 2015

California Council for Environmental and Economic Balance
101 Mission Street, Suite 1440, San Francisco, California 94105
415-512-7890 phone, 415-512-7897 fax, www.cceeb.org

October 19, 2015

Dr. Philip Fine, Deputy Executive Officer
Planning, Rules Development & Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, California 91765

RE: PAR 1110.2 and Startup, Shutdown and Malfunction (SSM) Policy

Dear Dr. Fine,

In a letter sent to you on August 17, 2015, the California Council for Environmental and Economic Balance (CCEEB) requested that sections in proposed amended rule (PAR) 1101.2 related to startup, shutdown, and malfunctions (SSM) be bifurcated and addressed in a separate process so that all impacted stakeholders could participate in development of the District's SSM policy. While CCEEB has no direct interest in the biogas engine provisions of 1101.2, the broader SSM policy potentially affects many of our members. 9-1

CCEEB reiterates our request and also asks staff to address and respond to questions and concerns raised by the Southern California Alliance of Publicly Owned Treatment Works (SCAP) and its coalition in their letter from October 15. Like SCAP, we believe that there has not been adequate discussion of potential approaches to the District's SSM policy or consideration of the legal implications stemming from litigation and policy interpretation differences of the federal EPA's new SSM policy. We believe that a bifurcated process could be implemented quickly, with active participation by all interested parties, and so we urge you to take this approach to PAR 1101.2. We hope to discuss this with you further, but in the meantime, please contact me with any questions. 9-2

Sincerely,

Bill Quinn

Bill Quinn
Vice President and Chief Operating Officer

cc: Jill Whynot
Joe Cassmassi

Responses to Letter #9

Response 9-1

The comment refers to the previous comment letter submitted on August 17, 2015 requesting bifurcation of the rule to address the EPA's and SCAQMD's SSM policy provisions. Please refer to Responses 4-1 through 4-3.

Response 9-2

The comment reiterates the requests of other commenters (SCAP and its coalition) from its October 15, 2015 comment letter. Please refer to Responses 8-1 through 8-7.

Comment Letter #10 – Fortistar Methane Group LLC, October 27, 2015

FORTISTAR METHANE GROUP LLC
One North Lexington Avenue □ White Plains, New York 10601
Tel. (914) 421-4900 □ Fax. (914) 421-0052

October 27, 2015

VIA Overnight Delivery

Barry R. Wallerstein, D.Env., Executive Officer
South Coast AQMD
21865 Copley Drive
Diamond Bar, CA 91765

Dear Mr. Wallerstein:

On behalf of Fortistar Methane Group LLC ("Fortistar") please accept this letter in conjunction with the rule-making process for SCAQMD Rule 1110.2 ("Rule"). As you know, Fortistar has been an active participant in the Rule 1110.2 "Working Group" and we appreciate the Board's collaborative approach relative to the proposed changes to the Rule. 10-1

On August 10, 2015, at the request of SCAQMD staff, Fortistar set forth in detail the steps it has taken to comply with the proposed Rule changes as relates to our MM Lopez Energy LLC ("Lopez) and Prima Deshecha LLC ("Prima") facilities. A copy of that letter is attached hereto.

In an effort to keep staff advised of our progress in connection with our Lopez facility since our August 10th letter, please be advised that our updated path is as follows:

- **9/3/15** – Staff made recommendation to Fortistar management for purchase of gas conditioning system.
- **10/30/15** - Conclude negotiations with Willexa regarding purchase terms and conditions with the goal of issuing a purchase order for a gas conditioning system. 10-2
- **11/13/15** - Submit an application to the SCAQMD for air permit modification.
- **11/23/15** - Electrical separation of Lopez engines to be complete and providing power to LADWP.
- **11/30/15** - Continue negotiations with equipment vendors and recommend procurement of an SCR system.
- **1/15/16** - Issue purchase order for SCR system.
- **7/13/16** - Delivery of gas conditioning system at Lopez anticipated.

1

- **10/10/16 -** System operational for testing following installation.

- **1/1/17 -** Lopez gas conditioning system and SCR system fully operational. **While our plans are to commence operation of the SCR system by this date, we firmly believe that a one-year (i.e. 1/1/18) shakeout period is absolutely required to ensure that the system will reliably operate for the term of the Lopez power purchase agreement with LADWP.** 10-2 cont.

We appreciate your consideration of Fortistar's genuine and substantial efforts in adopting compliance technology and the circumstances which we feel justify an extension of the compliance timelines at two of our Lopez facility. We understand that the rule making process is a complex one and we thank you for your receipt and evaluation of these comments. 10-3

Very truly yours,

Jonathan Maurer
Acting CEO
Fortistar Methane Group LLC

Encl.

cc: Rule Making Staff (via First Class Mail)

2

FORTISTAR METHANE GROUP LLC

One North Lexington Avenue ♦ White Plains, New York 10601
Tel. (914) 421-4900 ♦ Fax. (914) 421-0052

August 10, 2015

BY US POST

Mr. Mark Abromowitz
Board Consultant to Hon. Joseph Lyou
South Coast AQMD

Dear Mr. Abromowitz:

On behalf of Fortistar Methane Group LLC ("Fortistar") please accept this comment letter in conjunction with the rule-making process for SCAQMD Rule 1110.2 ("Rule"). As you know, Fortistar has been an active participant in the Rule 1110.2 "Working Group" and we appreciate the Board's collaborative approach relative to the proposed changes to the Rule.

At the July 2015 Working Group meeting, a draft set of proposed Rule changes were distributed which carve out additional time for compliance to two specific entities – the City of San Bernardino and the Eastern Municipal Water District. We greatly appreciated staff's decision to propose an additional compliance timeframe for these entities based on their early exploration and adoption of technology demonstration projects. We respectfully request that Fortistar and its associated sites subject to the Rule be considered for the same extension based on a similar level of investment and commitment to future compliance with the Rule.

Please know that after reviewing the course of events, it is clear that we have fallen short in sharing with staff the efforts we have taken which would justify such an extension, and are appreciative of your consideration of the information below which includes a description of our sites, our negotiations with equipment suppliers and economic considerations that we feel support our request.

1. **Overview of Fortistar Sites**

Six of Fortistar's project entities are affected by the pending implementation Rule 1110.2. They are:

1. MM Lopez Energy LLC - (Los Angeles County)
2. MM Prima Desheca Energy LLC- (Orange County)
3. Coyote Canyon Energy LLC – (Orange County)
4. NM Milliken Genco LLC – (San Bernardino County)
5. NM Mid Valley Genco LLC - (San Bernardino County)
6. NM Colton LLC – (San Bernardino County)

Of these six facilities, four (Milliken, Mid Valley, Coyote Canyon, and Colton) have either recently been shut down or will shortly be shut down for economic reasons unrelated to Rule

1

1110.2. The remaining two facilities, Lopez and Prima continue to operate and are the focus of this briefing.

2. Lopez Facility, Los Angeles County

Currently, Lopez has two functioning engines that deliver energy. Lopez was accepted into the LADWP FIT Program in June 2014. Prior to that, it was clear that the project's power purchase agreement, with a ten-year term beginning in 2006, did not generate sufficient cash flow to support the installation of equipment required by Rule 1110.2.

With Lopez's acceptance into the LADWP FIT program in June 2014, Fortistar became actively engaged, investing in plans and specifications that will result in a fully engineered selective catalytic reduction (SCR) system for one of the two engines[1]. We have attached as Exhibit A our efforts to explore and invest in this technology. We are committed to install this system in 2016. After an appropriate shakeout period, the engine will be fully operational and compliant in 2017. Given this timeframe, and our existing investment in this technology, *we would respectfully request the Lopez project be allowed a compliance extension date of January 1, 2018.*

We believe the facts are clear that Fortistar has expended substantial efforts to employing an SRS Rule 1110.2-compliant system. Fortistar initially invested in the analysis of several alternative technologies and, as described below, in 2014 selected DCL International, Inc. ("DCL) which we determined had the highest probability of reliability. DCL was to build a plant for another party that we could review and was also to provide a guarantee on operations. We have since come to learn that the construction project is delayed and the guarantee is different than from what we initially anticipated.

Specifically, Fortistar initiated discussions with equipment suppliers for compliant equipment upgrades in June 2014 including DCL and Airflow Catalyst Systems. Fortistar developed a strong interest in DCL's approach due to DCL's stated ability to provide a firm guarantee that encompassed the entire scope of equipment supply. This single vendor concept is important to Fortistar because procuring gas conditioning equipment and exhaust gas treatment from separate vendors inherently creates more operational and warranty risk should the equipment ultimately fail to provide the gas quality required for our PPA partners. Accordingly, from the beginning of our discussions with DCL we required operational data to confirm the proposed equipment's effectiveness. Unfortunately, for various reasons, DCL has not yet provided the data to Fortistar and the equipment guarantee has not materialized in an acceptable form.

Although we continue to work with DCL in pursuit of data proving the effectiveness of their proposed equipment and warranty, we are now actively working with other vendors to comply with the Rule. For gas conditioning we are in discussions with Parker and Willexa relative to equipment proposals. For the SCR system we are engaged in active discussions with Miratech as an alternative to AeriNOx (a DCL affiliated company). Our first priority, based on engineering, production and delivery constraints, is the procurement of the gas conditioning equipment. We are informed, the expected production timeline for this component is approximately 26 weeks from approved drawings with 4-6 weeks being required for submittal drawing preparation. Allowing 2 weeks to

[1] The second engine is scheduled for shut-down consistent with the implementation date of Rule 1110.2.

2

review/approve drawings, this amounts to approximately 34 weeks to deliver a gas conditioning system.

As you can see from Exhibit A, we have been substantially involved in the vetting of new compliance technologies and have invested resources – financial and otherwise – in exploring all options. Our proposed path forward for Lopez is:

- Continue negotiations with equipment vendors so that a recommendation can be made to Fortistar management for procurement of a gas conditioning system by **8/31/15.**
- Issue purchase order for gas conditioning system on or about **9/30/15** and subject to Fortistar's satisfaction of the reliability of the equipment.
- Electrical separation of Lopez engines complete and providing power to LADWP by **10/30/15.**
- Continue negotiations with equipment vendors and recommend procurement of an SCR system by **10/30/15.**
- Issue purchase order for SCR system by **1/15/16.**
- Delivery of gas conditioning system at Lopez expected by **6/1/16.**
- System operational for testing following installation by **10/1/16.**
- Lopez gas conditioning system and SCR system fully operational by **1/1/17. Note: Shake out period and reliable functioning by 1/1/18 .**

However, the decision to analyze and deploy new technology does not exist in a vacuum. Like other entities, Fortistar continues to make these decisions against the backdrop of the economic climate in which it operates. This is evident considering our experience at Prima Desheca.

3. Prima Descheca

Although the Lopez site is our test bed for our integration of compliance technologies, economic factors make the Prima Descheca ("Prima") site more challenging. Prima entered into a power purchase agreement (PPA) with SDG&E in 2008 which expires on October 1, 2022. The power pricing is in the high $50/MW-hour range. The low power price and short term remaining on the PPA do not provide for adequate revenue or operating life to recover the installation and operational costs of the necessary equipment for Rule 1110.2 compliance. The project has an annual net profit of approximately $200,000. In addition, the project has posted an approximate $940,000 letter of credit securing its obligation to deliver electricity to SDG&E for the term of the PPA. If required to comply with Rule 1110.2, the project would be forced to shut down effective by January 2017, resulting in an approximate loss of $2,500,000 in revenues, including the loss of the letter of credit.

3

Further, with annual Compliance Flexibility Payments estimated at $390,000, these obligations alone are far in excess of annual profits which makes it uneconomic to continue operations. Given these facts, *we believe it is equitable to request that the Prima project be grandfathered under existing rules and be permitted to operate until the expiration of the current term of the SDG&E PPA, or October 1, 2022*.

4. Conclusion

We appreciate your consideration of Fortistar's genuine and substantial efforts in adopting compliance technology and the circumstances, which we feel justify an extension of the compliance timelines at two of our facilities. We understand that the rule making process is a complex one and we thank you for your receipt and evaluation of these comments.

Very truly yours,

Jonathan Maurer

Jonathan Maurer
Acting CEO
Fortistar Methane Group, LLC

4

EXHIBIT A: TIMELINE OF EFFORTS TO COMPLY WITH RULE 1011.2

The following is a timeline of actions taken relative to procurement of equipment necessary for compliance with Rule 1110.2. Many communications with DCL and other vendors have taken place in addition to these events:

- **June 2014** – Acceptance of Fortistar proposal by LADWP for power under the LADWP FIT program. Until this date, Fortistar did not have a viable financial model for installation of equipment required by rule 1110.2. **The project was approved and funded subject to conditions required for financing (i.e. executed PPA). This included the installation of equipment required by rule 1110.2.**
- **September 2014** – Project Development scoping meeting conducted at DCL office in Toronto, Canada.
- **9/16/14** – DCL visits Lopez site and draws gas samples collected for use in development of the preliminary design of the gas conditioning and SCR systems.
- **9/30/14** – Fortistar received quote for gas conditioning and purification system from DCL.
- **10/2/14** – Gas analytical report received from 9/16/14 samples.
- **10/3/14** – Fortistar received quote for catalytic guard bed from DCL.
- **10/31/14** – Fortistar received revised proposal from AeriNOx for SCR system based on ongoing discussions with the vendor.
- **10/31/15** – Fortistar completed development and was in a position to execute PPA with LADWP; we deferred execution to request some contract cleanup items.
- **2/10/15** – Fortistar received a revised quote from DCL for gas conditioning and catalytic guard systems based on ongoing discussions with the vendor. Met with DCL prior to 1110.2 meeting and were told to expect operational data imminently. Fortistar expressed willingness to execute a Purchase Order with DCL once data was reviewed.
- **2/26/15** – Gas sampling for additional VOC data.
- **3/18/15** – Met with DCL in New Orleans and were told to expect operational data imminently.
- **3/31/15** – Fortistar received the cleanup items on the terms of the LADWP PPA and executed the contract.
- **4/9/15** – Receipt of fully executed PPA from LADWP for Lopez project. **It is important to note that this was a requirement for financing of the project.**
- **4/22/15** – Fortistar requested quote from Miratech for SCR system.

5

Responses to Letter #10

Response 10-1

This introductory comment explains that this comment letter was submitted in conjunction with the rule-making process for the proposed amendments to Rule 1110.2. Thus, responses to the specific comments are presented in Responses 10-2 and 10-3.

Response 10-2

The commenter has included its previous comment letter submitted on August 10, 2015, and has provided an updated installation schedule for its Lopez facility. The commenter also reiterates that a one-year shake out period is required to ensure reliable control system operation.

Staff appreciates the update and acknowledges Fortistar's commitment to the installation of biogas engine control technology at the Lopez facility. Please refer to Response 1-3.

Response 10-3

The comment requests an extension of the compliance date without payment of a fee. Please refer to Response 1-3.

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Subsequent Environmental Assessment for:

Proposed Amended Rule 1110.2 - Emissions From Gaseous-and Liquid-Fueled Engines

December 2015

SCAQMD No. 150728CC
State Clearing House No. 2015071072

Executive Officer
Barry R. Wallerstein, D. Env.

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 and Rules Manager
Planning, Rule Development and Area Sources
Ian MacMillan

Author:	Cynthia A. Carter	Air Quality Specialist
	Jeffrey Inabinet	Air Quality Specialist
Technical Assistance:	Kevin Orellana	Air Quality Specialist
Reviewed By:	Jillian Wong, Ph.D.	CEQA Program Supervisor
	Barbara Baird	Chief Deputy Counsel
	William Wong	Principal Deputy District Counsel
	Gary Quinn, P.E.	Program Supervisor

PREFACE

This document constitutes the Final Subsequent Environmental Assessment (SEA) for Proposed Amended Rule 1110.2 - Emissions from Gaseous- and Liquid-Fueled Engines. A Notice of Preparation and Initial Study (NOP/IS) was prepared and distributed to responsible agencies and interested parties for a 30-day review and comment period from July 29, 2015 through August 27, 2015. No comment letters were received during the public comment period. The NOP/IS identified potential adverse impacts in the following one environmental topic: air quality and greenhouse gas emissions as a result of delaying compliance with the existing lower NOx, CO, and VOC emission limits. No comment letters were received from the public regarding the preliminary analysis in the NOP/IS. A CEQA scoping meeting was held on Thursday, August 13, 2015 at 10 AM in Conference Room GB at SCAQMD Headquarters. No comments were received at the scoping meeting.

The Draft SEA was circulated for a 45-day public review and comment from September 1, 2015 to October 16, 2015, which identified the topic of air quality and greenhouse gas emissions as exceeding the SCAQMD's significance thresholds associated with implementing the proposed project. No comments were received on the Draft SEA.

Subsequent to release of the Draft SEA, minor modifications were made to the proposed project, including the classification of the Orange County Sanitation District (OCSD) project as a "demonstration project" and the addition of a proposal for the breakdown provision provided by the affected industries. To facilitate identification, modifications to the document are included as <u>underlined text</u> and text removed from the document is indicated by ~~strikethrough~~.

Staff has reviewed the modifications to the proposed project and concluded that none of the revisions constitute: 1) significant new information; 2) a substantial increase in the severity of an environmental impact; or, 3) provide new information of substantial importance relative to the draft document. In addition, revisions to the proposed project would not create new, avoidable significant effects. As a result, these revisions do not require recirculation of the document pursuant to CEQA Guidelines §15073.5 and §15088.5. Therefore, this document now constitutes the Final SEA for the proposed project.

TABLE OF CONTENTS

TABLE OF CONTENTS
(Continued)

CHAPTER 1

INTRODUCTION AND EXECUTIVE SUMMARY

INTRODUCTION

The California Legislature adopted the Lewis-Presley Air Quality Act in 1976, which created the South Coast Air Quality Management District (SCAQMD) from a voluntary association of air pollution control districts in Los Angeles, Orange, Riverside, and San Bernardino counties. The agency was charged with developing uniform plans and programs for the South Coast Air Basin (Basin) to attain federal air quality standards by the dates specified in federal law. While the Basin has one of the worst air quality problems in the nation, there have been significant improvements in air quality in the Basin over the last three decades. Still, some air quality standards are exceeded relatively frequently, and by a wide margin. The agency was also required to meet state standards by the earliest date achievable through the use of reasonably available or all feasible control measures.

The SCAQMD is proposing to amend a rule, Proposed Amended Rule (PAR) 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines. Currently, Rule 1110.2 limits emissions of nitrogen oxides (NOx), volatile organic compounds (VOCs) and carbon monoxide (CO) from the combustion of gaseous and liquid fueled engines. This rule applies to engines that are operating in the SCAQMD and that are rated more than 50 rated brake horsepower (bhp). The rule was adopted in 1990 and last amended in 2012 to establish an effective date of January 1, 2016 for owners and operators of biogas engines to meet the emission limits that all other engines under this rule were required to meet in July 1, 2011.

There are two key issues to be resolved in this amendment:

1. SCAQMD staff's recent evaluation of the state of compliance with Rule 1110.2 as well as feedback from industry revealed that some equipment owners/operators are experiencing compliance challenges, in particular, with certain effective dates in the rule. Because some control technologies have not matured in a timely manner for biogas engines, SCAQMD staff is proposing to amend Rule 1110.2 to delay implementation of NOx, VOC, and CO emission limits compliance dates for biogas engines. The delayed emission reductions are greater than the SCAQMD's significance threshold, thus the air quality impacts from PAR 1110.2 are considered significant. However, all emission reductions will be recaptured over time, so the impacts are not permanent.
2. Limits are being proposed on the number of breakdowns and excess emissions during breakdown events in order to be consistent with the EPA's breakdown provisions and to allow the rule to be included in the State Implementation Plan (SIP).

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

The proposed amendments to Rule 1110.2 are considered a "project" as defined by CEQA. CEQA requires that the potential adverse environmental impacts of proposed projects be evaluated and that methods to reduce or avoid identified significant adverse environmental impacts of these projects be implemented if feasible. The purpose of the CEQA process is to inform the SCAQMD's Governing Board, public agencies, and interested parties of potential adverse environmental impacts that could result from implementing the proposed project and to identify feasible mitigation measures or alternatives, when an impact is significant.

California Public Resources Code §21080.5 allows public agencies with regulatory programs to prepare a plan or other written documents in lieu of an environmental impact report once the Secretary of the Resources Agency has certified the regulatory program. The SCAQMD's regulatory program was certified by the Secretary of Resources Agency on March 1, 1989, and is codified as SCAQMD Rule 110. Pursuant to Rule 110 (the rule which implements the SCAQMD's certified regulatory program), SCAQMD is preparing a ~~Draft~~Final Subsequent Environmental Assessment (SEA) to evaluate potential adverse impacts from the proposed project. A SEA is the appropriate CEQA document for the proposed project because there are subsequent changes proposed to Rule 1110.2 (CEQA Guidelines §15162). The proposed project is a modification of two earlier projects (December 2007 Final EA, Certified on February 1, 2008 and August 2012 Addendum to the 2007 Final EA, Certified on September 7, 2012) and this analysis considers only the incremental effects of the proposed project.

A Notice of Preparation and Initial Study (NOP/IS) was prepared and distributed to responsible agencies and interested parties for a 30-day review and comment period from July 29, 2015 through August 27, 2015. No comment letters were received during the public comment period. The NOP/IS identified potential adverse impacts in the following one environmental topic: air quality and greenhouse gas emissions as a result of delaying compliance with the existing lower NOx, CO, and VOC emission limits.

The Draft SEA was circulated for a 45-day public review and comment from September 1, 2015 to October 16, 2015, which identified the topic of air quality and greenhouse gas emissions as exceeding the SCAQMD's significance thresholds associated with implementing the proposed project. No comments were received on the Draft SEA.

Subsequent to release of the Draft SEA, modifications were made to the proposed project including the classification of the OCSD project as a "demonstration project" and the addition of a proposal for the breakdown provision provided by the affected industries. Staff has reviewed the modifications to the proposed project and concluded that none of the revisions constitute: 1) significant new information; 2) a substantial increase in the severity of an environmental impact; or, 3) provide new information of substantial importance relative to the draft document. In addition, revisions to the proposed project would not create new, avoidable significant effects. As a result, these revisions do not require recirculation of the document pursuant to CEQA Guidelines §15073.5 and §15088.5. Therefore, this document now constitutes the Final SEA for the proposed project.

Thus, this Final SEA, prepared pursuant to CEQA Guidelines §15132, identifies air quality and greenhouse gas emissions as areas that may be adversely affected by the proposed project. Prior to making a decision on the adoption of the proposed amendments to Rule 1110.2, the SCAQMD Governing Board must review and certify the Final SEA as providing adequate information on the potential adverse environmental impacts that may occur as a result of adopting the proposed amendments to Rule 1110.2.

PAST CEQA DOCUMENTATION FOR RULE 1110.2

Rule 1110.2, like other SCAQMD rules and regulations, comprises a regulatory program that changes over time due to advances in technology, regulatory requirements adopted by state and federal agencies, advances in technology not occurring as anticipated, etc. To reflect these changes, Rule 1110.2 has been amended a number of times since its original adoption in 1990. The following subsections describe the type of CEQA documents prepared for past amendments to

Rule 1110.2 and summarize the modifications and analyses prepared for those documents. The current SEA focuses on the currently proposed amendments to Rule 1110.2 and relies on the previously prepared December 2007 Final EA and August 2012 Addendum to the 2007 Final EA as described below.

Addendum to the 2007 Final EA for Proposed Amended Rule 1110.2 – Emissions from Gaseous - and Liquid-Fueled Engines; August 2012: An addendum was prepared for the 2012 amendments to Rule 1110.2. This action made certain limits effective that were already adopted and analyzed in a California Environmental Quality Act (CEQA) document for the amendments to Rule 1110.2 adopted in 2008, which established new exhaust emission concentration limits for landfill and digester gas-fired engines to take effect July 1, 2012. These limits did not take effect because they were contingent upon completion of a technology assessment by July 2010. Except for CO, the emission standards would be equivalent to the current best available control technology (BACT) for NOx and VOC for new internal combustion engines. Among the engines affected by the 2012 amendments were approximately 55 engines that are fired by landfill or digester gas (biogas), located at 13 public and private landfills and wastewater treatment plants. The SCAQMD concluded that the amendments would not change the environmental analysis or conclusions in the previously certified December 2007 Final EA. Pursuant to CEQA Guidelines §15164 (c), it was not necessary to circulate the Addendum for public review. The Addendum to the 2012 Final EA was certified by the SCAQMD Governing Board on September 7, 2012. This document can be obtained by visiting the following website at: http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2012/addendum-to-the-2007-final-environmental-assessment-for-proposed-amended-rule-1110-2.pdf

Final EA for Proposed Amended Rule 1110.2; December 2007: The amendments to Rule 1110.2 were to further reduce NOx, VOC and CO emissions from gaseous and liquid-fueled ICEs. PAR 1110.2 would partially implement the 2007 AQMP Control Measure MCS-01 – Facility Modernization, which required facilities to retrofit or replace their equipment to achieve emission levels equivalent to best available control technology (BACT). The amendments affected stationary, non-emergency engines and increased monitoring requirements; reduced the emission standards equivalent to the current BACT; required new electrical generating engines to meet the same requirements as large central power plants; and clarify portable engine requirements. The analysis showed that there were potential adverse environmental effects. The Draft EA identified air quality, hazards and hazardous materials, and solid/hazard wastes as environmental topic areas that may be adversely affected by the proposed project. 45-day public review and comment period from November 2, 2007 to December 18, 2007. One public comment letter was received and responses were prepared. Some significant adverse impacts were mitigated to less than significant and a mitigation monitoring plan was prepared. After circulation of the Draft EA, a Final EA was prepared and certified by the SCAQMD Governing Board on February 1, 2008. This document can be obtained by visiting the following website: http://www.aqmd.gov/home/library/documents-support-material/lead-agency-scaqmd-projects/aqmd-projects---year-2008/fea-for-par-1110-2

Final EA for Proposed Amended Rule 1110.2, June 2005: A Draft EA for the proposed Rule 1110.2 was released for a 30-day public review period from March 18, 2005, to April 19, 2005. Proposed amendments to Rule 1101.2 included: removing exemption for all agricultural engines except emergency standby engines and engines powering orchard wind machines; adding more recordkeeping requirements; prohibiting use of portable engine generators to supply power to the grid or to a building, facility, stationary source or stationary equipment except in an emergency affecting grid stability; and removing outdated rule language. Rule 1110.1 was rescinded because it is superseded by the requirements of Rule 1110.2. After circulation of the Draft EA, a Final EA was prepared and certified by the SCAQMD Governing Board on June 3, 2005.

Final Subsequent EA for the Proposed Amended Rule 1110.2, November 14, 1997: Proposed amendments were made to address portable engine requirements under Rule 1110.2 and CARB's Statewide Portable Engine and Equipment Registration Regulation. Significant adverse impacts were identified and evaluated for air quality and energy. The Draft SEA was released for a 45-day public review and comment period from September 10, 1997 to October 28, 1997. No comments were received from the public.

Notice of Exemption (NOE) for the Proposed Amended Rule 1110.2, December 9, 1994: The proposed amendments clarified the meaning of the terms "originally installed" for purposes of determining compliance with the rule. A NOE was prepared for proposed amended Rule 1110.2, because the proposed amendments were administrative in nature and had no significant adverse impacts on the environment.

Notice of Exemption (NOE) for the Proposed Amended Rule 1110.2, August 12, 1994: The proposed amendments clarified the original intent that continuous in-stack CO monitoring system is not required if a continuous in-stack NOx monitoring system is not required. The proposed amendments harmonized Rule 1110.2 and RECLAIM.

Final EA for Proposed Rule 1110.2, September 7, 1990: The Governing Board requested that staff examine issues during the adoption hearing for Rule 1110.2 and provide recommendations. Clarification of monitoring and periodic emission testing for engines over 1,000 bhp was added for NOx and CO emissions. A limited exemption was proposed for up-slope units at winter resort facilities that are operated less than 700 hours per year. Since the circumstances of the original project and the modifications were essentially the same, the Final EA for Proposed Rule 1110.2 was recertified for these changes.

Final EA for Proposed Rule 1110.2, August 3, 1990: A Draft EA for the proposed rule was released for a 45-day public review period from May 25, 1990, to July 25, 1990. Four comment letters were received and responses were prepared. The EIR identified potential impacts and mitigation measures for water quality, risk of upset, transportation, energy, solid waste disposal, and human health. Significant adverse impacts were mitigated to less than significant. A mitigation monitoring plan was prepared.

Intended Uses of this Document

In general, a CEQA document is an informational document that informs a public agency's decision-makers and the public generally of potentially significant environmental effects of a project, identifies possible ways to avoid or minimize the significant effects, and describes reasonable alternatives to the project (CEQA Guidelines §15121). A public agency's decision-makers must consider the information in a CEQA document prior to making a decision on the project. Accordingly, this ~~Draft~~Final SEA is intended to: a) provide the SCAQMD Governing Board and the public with information on the environmental effects of the proposed project; and,

b) be used as a tool by the SCAQMD Governing Board to facilitate decision making on the proposed project.

AREAS OF CONTROVERSY

In accordance with CEQA Guidelines §15123 (b)(2), the areas of controversy known to the lead agency, including issues raised by agencies and the public, shall be identified in the CEQA document. The following discussion identifies potential areas of controversy relating to PAR 1110.2.

The Need for Additional Time to Comply. The affected industry has raised concerns with meeting the Rule 1110.2 requirements because control technologies have not matured in a timely manner for biogas engines. On this basis, SCAQMD staff is proposing to delay the compliance dates and have the biogas engines on a more suitable compliance schedule with achievable emission limitations. However, due to the proposed delayed compliance schedule, the proposed amendment will result in a delay of: 0.9 tons/day of NOx, 0.5 tons/day of VOC, and 20 tons/day of CO emission reductions. Nonetheless, these delayed emission reductions will be recaptured in compliance years 2017 and 2018, respectively. See Table 1-1 for details.

Table 1-1
PAR 1110.2 Delayed Emissions Reductions

Compliance Extension	***Type of Project***	***NOx (tpd)***	***VOC (tpd)***	***CO (tpd)***
January 1, 2017	Emission Reductions delayed for January 1, 2017 Compliance Date (non-demonstration project ICEs)	~~0.87~~0.63	~~0.39~~0.19	~~18.25~~16.25
January 1, 2018	Emission Reductions delayed for January 1, 2018 Compliance Date (demonstration project ICEs)	~~0.04~~0.28	~~0.09~~0.29	~~1.75~~3.75
	Total	**0.9**	**0.5**	**20**

Since the Draft SEA was released for public review and comment, OCSD staff contacted SCAQMD staff and requested that the OCSD project be classified as a "demonstration project", which gives OCSD an additional year to comply with the requirements of PAR 1110.2. In doing so, the emissions reductions delayed from the OCSD project would shift from 2017 to 2018. Please refer to Chapter 4 for a discussion of the air quality impacts associated with this change.

Complying with EPA's Breakdown Provisions. The affected industry has concerns regarding the criteria for a breakdown and the incidence per quarter limit associated with it. Therefore, a proposal for the breakdown provision provided by the affected industries has been included as an alternative rule proposal. As described on Page 4-2 of the Draft SEA, in order to ensure a "worst-case" analysis, PAR 1110.2 impacts from limiting breakdowns were not quantified and credit was not taken for those reductions in emissions. Therefore, the addition of a proposal to the proposed rule amendment for the breakdown provisions provided by the affected industries would not affect the analysis of environmental impacts in the Draft SEA or create new, avoidable significant effects.

EXECUTIVE SUMMARY

Chapter 2 – Project Description and Project Objectives

The proposed project consists of amending Rule 1110.2, which would provide biogas fired engines additional time to comply with the rule's emission limits and limit the number of breakdowns with resultant excess emissions for all engines.

Stakeholders have been concerned throughout the rulemaking process that achieving the lower concentration limits by January 1, 2016 is not feasible and operators needed more time (implementation by mid-2016 to mid-2018). The ongoing biogas technology demonstration projects have encountered delays and operational issues. Because these projects have not been completed, SCAQMD staff is proposing to delay implementation to 2017 for non-demonstration projects and 2018 for demonstration projects of the biogas emission limits.

PAR 1110.2 also includes an option for an alternate compliance plan with payment of a compliance flexibility fee to delay compliance. The alternate compliance plan option allows facilities to phase in compliance up to one additional year for their equipment.

SCAQMD staff is proposing to address EPA's concerns and has approved SCAQMD's proposal with equipment breakdowns and potential excess emissions without enforcement by establishing a limit for exceedances due to breakdowns without enforcement action per calendar quarter.

<u>An alternative rule proposal has been included that would remove rule language stating that breakdowns are not violations and adding suggested U.S. EPA language making clear that breakdowns would subject operators to potential federal enforcement action or citizen lawsuits</u>

The project objectives are as follows:

- to maintain the lower limits on NOx, VOC, and CO emissions from the combustion of gaseous and liquid biogas engines;
- place biogas engines on a more suitable compliance schedule with achievable emission limitations due to the fact that demonstration project control technologies have not matured in a timely manner for these types of engines and to meet the construction schedules for established SCR technology;
- to comply with EPA Breakdown provision requirements; and
- aside from temporary air quality impacts, avoid generating any new adverse environmental impacts.

Chapter 3 – Existing Setting

Pursuant to the CEQA Guidelines §15125, Chapter 3 – Existing Setting, includes descriptions of those environmental areas that could be adversely affected by the proposed project as identified in the NOP/IS (See Appendix C). The following subsection briefly highlights the existing setting for the topic of air quality which has been identified as having potentially significant adverse effects from implementing the proposed project.

<u>Air Quality</u>

This section provides an overview of air quality in the District whose region could be affected by the proposed project. Air quality in the area of the SCAQMD's jurisdiction has shown substantial improvement over the last three decades. Nevertheless, some federal and state air quality standards are still exceeded frequently and by a wide margin. Of the National Ambient Air Quality Standards (NAAQS) established for seven criteria pollutants (ozone, lead, sulfur dioxide, nitrogen dioxide, carbon monoxide, PM10 and PM2.5), the area within the SCAQMD's jurisdiction is only in attainment for carbon monoxide, PM10, sulfur dioxide, and nitrogen dioxide standards. Air monitoring for PM10 indicates that SCAQMD has attained the NAAQS and the USEPA published approval of SCAQMD's PM10 attainment plan on June 26, 2013, with an implementation date of July 26, 2013. Effective December 31, 2010, the Los Angeles County portion of the SCAQMD has been designated as non-attainment for the new federal standard for lead, based on emissions from two specific facilities. While there has been no recent exceedances of the lead NAAQS, the area has not been redesignated as "attainment". Chapter 3 provides a brief description of the existing air quality setting for each criteria pollutant, as well as the human health effects resulting from exposure to each criteria pollutant. In addition, this section includes a discussion on greenhouse gas (GHG) emissions, climate change and toxic air contaminants (TACs).

Chapter 4 – Environmental Impacts

The CEQA Guidelines require environmental documents to identify significant environmental effects that may result from a proposed project [CEQA Guidelines §15126.2 (a)]. Direct and indirect significant effects of a project on the environment should be identified and described, with consideration given to both short- and long-term impacts. The following subsection briefly highlights the environmental impacts and mitigation measures for the topic of air quality which has been identified as having potentially significant adverse effects from implementing the proposed project.

<u>Air Quality</u>

This section provides an overview of the potential adverse air quality emissions impacts from the proposed project. The initial evaluation in the NOP/IS (see Appendix C) identified the topic of air quality as potentially being adversely affected by the proposed project. The affected equipment consists of liquid and gas fueled internal combustion (IC) engines operating in the SCAQMD rated more than 50 rated bhp. SCAQMD staff is proposing limits to be placed on the number of breakdowns and resultant excess emissions during breakdown events. Additionally, due to the fact that demonstration project control technologies have not matured in a timely manner for biogas engines, the proposed project would place biogas engines on a more suitable compliance schedule with achievable emission limitations during the interim.

PAR 1110.2 impacts from limiting breakdowns will not be quantified and credit will not be taken for those reductions in emissions. Impacts from delaying compliance implementation for 55 biogas engines are 0.9 tons/day of NOx, 0.5 tons/day of VOC, and 20 tons/day of CO emission reductions (see Table 1-1). It is expected that most of these biogas engines will be able to comply with the proposed emission limits by mid-2016 to mid-2018. The methods of compliance will be to meet the proposed NOx, VOC, and CO emission limits by January 1, 2017 or choose to pay a compliance flexibility fee for additional time. The new proposed project NOx, VOC and CO emission limits and compliance schedule are provided in Table 1-2. Construction impacts have been already analyzed in the 2007 Final EA.

Table 1-2
Proposed Concentration Limits for Biogas Engines

CONCENTRATION LIMITS FOR LANDFILL AND DIGESTER GAS (BIOGAS)-FIRED ENGINES		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 36 x ECF[3] bhp < 500: 45 x ECF[3]	Landfill Gas: 40 Digester Gas: 250 x ECF[3]	2000
CONCENTRATION LIMITS EFFECTIVE JANUARY 1, 2017		
NOx (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250

1 Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.
2 Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.
3 ECF is the efficiency correction factor.

For operators of biogas engine demonstration projects, the compliance date will be extended to January 1, 2018. A new subparagraph (d)(1)(F) will specify the operators referenced previously who are still undergoing demonstration projects.

> “For the City of San Bernardino and Eastern Municipal Water District that commenced and implemented technology demonstration projects prior to January 1, 2015, all their biogas engines shall have until January 1, 2018 to comply with the requirements of Table III-B.”

Since the Draft SEA was released for public review and comment, OCSD staff contacted SCAQMD staff and requested that the OCSD project be classified as a “demonstration project”, which gives OCSD an additional year to comply with the requirements of PAR 1110.2. In doing so, the emissions reductions delayed from the OCSD project would shift from 2017 to 2018. Please refer to Chapter 4 for a discussion of the air quality impacts associated with this change.

NOx, CO, and VOC emission reductions for PAR 1110.2 would be delayed and would result in approximately 0.9 tons/day of NOx, 0.5 tons/day of VOC, and 20 tons/day of CO emissions foregone. However, these delayed emission reductions will be recaptured in compliance years 2017 and 2018, respectively. The quantity of delayed NOx, VOC, and CO emission reductions exceeds the SCAQMD CEQA significance thresholds. Thus, PAR 1110.2 will result in adverse significant operational air quality impacts. The air quality analysis presented in Chapter 4 represents a "worst-case" analysis and accounts for these potential additional delays in compliance.

The compliance flexibility fee option for PAR 1110.2 is the same compliance fee program that currently exists in Rule 1110.2. In Rule 1110.2, all compliance flexibility fees are used to reduce NOx emissions through the SCAQMD's leaf blower exchange program and any other similar NOx reduction programs. The fees collected as a result of the implementation of PAR 1110.2 from the affected facilities electing to use the mitigation fee option will still be used in the same manner. By funding this program, emission reductions will be generated to provide a regional air quality benefit to reduce the impacts from the potential delays in emission reductions from those facilities choosing to delay compliance. It is possible that the use of these fees will fully offset the adverse air quality impact, but this cannot be guaranteed at this time. There are no further feasible mitigation measures that have been identified at this time that would reduce or eliminate the expected delays in emission reductions. Consequently, the operational air quality emissions impacts from the proposed project cannot be mitigated to less than significant.

Chapter 5 – Alternatives

The proposed project and four alternatives to the proposed project are summarized below in Table 1-3: Alternative A (No Project), Alternative B (Additional Delayed Compliance), Alternative C (Replace Flares) and Alternative D (New Micro Turbines). Pursuant to CEQA Guidelines §15126.6 (b), the purpose of an alternatives analysis is to reduce or avoid potentially significant adverse effects that a project may have on the environment. The environmental topic area identified in the NOP/IS that may be adversely affected by the proposed project was air quality impacts. A comprehensive analysis of air quality impacts is included in Chapter 4 of this document. In addition to identifying project alternatives, Chapter 5 provides a comparison of the potential operational impacts to air quality emissions from each of the project alternatives relative to the proposed project, which are summarized below in Table 1-4. Aside from these topics, no other potential significant adverse impacts were identified for the proposed project or any of the project alternatives. As indicated in the following discussions, the proposed project is considered to provide the best balance between meeting the objectives of the project while minimizing potentially significant adverse environmental impacts.

Table 1-3
Summary of PAR 1110.2 and Project Alternatives

Project	Project Description
Alternative A (No Project)	The proposed project would not be adopted and the current universe of equipment will continue to be subject to the NOx, VOC and CO emission limits according to the current compliance schedule in Rule 1110.2. If facilities cannot comply with the existing rule, operators may shut down their biogas engines and release their gas through their existing flares. Additionally, if potential gross emission violations during preventable breakdowns occur, corrective actions may not ensue. By not resolving this issue, this will result in EPA not approving the 2010 amendment into the State Implementation Plan (SIP). If this disapproval is finalized, sanctions would be imposed unless the U.S. EPA approves subsequent SIP revisions that correct the rule deficiencies within 18 months of disapproval.
Alternative B (Additional Delayed Compliance)	Provides additional delay of NOx, CO, and VOC emission limits compliance requirements for affected facilities beyond the proposed project. All other requirements and conditions in the proposed project would be applicable.
Alternative C (Replace Flares)	Through additional rule making, the facilities not meeting the current Rule 1110.2 biogas emission limits would be required to process the biogas through new cleaner and efficient flares (ultra-low NOx Bekaert Clean Enclosed Burner®; Bekaert CEB®) under a separate rule. The new flares' emissions would be comparable to the NOx, CO, and VOC emission limits of the proposed project. All other requirements and conditions in the proposed project would be applicable.
Alternative D (New Micro Turbines)	Through additional rule making, the facilities not meeting the current Rule 1110.2 biogas emission limits would be required to process the biogas through new micro turbines (Capstone C65) to handle their facilities' biogas. All other requirements and conditions in the proposed project would be applicable.

Table 1-4
Comparison of Adverse Environmental Impacts of the Alternatives

Category	Proposed Project	Alternative A: No Project	Alternative B: Additional Delayed Compliance	Alternative C: Replace Flares	Alternative D: New Micro Turbines
Air Quality Impacts: Construction	This proposed amendment does not have any construction impacts. Construction impacts were analyzed for the 2007 PAR 1110.2 EA.	No construction impacts.	Same as proposed project.	Same as proposed project.	Same as proposed project.
Significant?	No	No	No	No	No
Air Quality Impacts: Operation	Approximately 0.9 tons of NOx, 0.5 tons/day of VOC, and 20 tons/day of CO peak daily emission reductions delayed; increases emission reductions from air quality improvement projects funded by compliance flexibility fee in Rule 1110.2.	Fewer emissions than proposed project due to no delay in emission reductions from proposed project; similar anticipated emission reductions from air quality improvement projects funded by compliance flexibility fee in Rule 1110.2.	More delayed emission reductions than proposed project due to additional compliance delay; potentially less emission reductions from air quality improvement projects funded by compliance flexibility fee in Rule 1110.2.	Due to the new flares being more efficient in combustion than the biogas engines, there would be less NOx, VOC and CO emissions than the proposed project. There would be additional emissions from power plants and backup engines. Thus, these emissions would still exceed the SCAQMD CEQA significance thresholds for operation.	Due to the new microturbines being more efficient in combustion than the biogas engines, there would be less NOx and CO emissions than the proposed project. There would be an increase in VOC emissions compared to the proposed project. There would be additional emissions from backup engines. Thus, these emissions would still exceed the SCAQMD CEQA significance thresholds for operation.
Significant?	Yes	No	Yes	Yes	Yes

Category	Proposed Project	Alternative A: No Project	Alternative B: Additional Delayed Compliance	Alternative C: Replace Flares	Alternative D: New Micro Turbines
Air Quality Impacts: GHG	None. Control equipment only controls NOx, VOC, and CO emissions.	Same as proposed project	Same as proposed project	GHG emissions would increase from power plants and back up diesel engines. However the emissions are less than the SCAQMD CEQA significance threshold for GHG.	GHG emissions would increase from back up diesel engines. However, the emissions are less than the SCAQMD CEQA significance threshold for GHG.
Significant?	No	No	No	No	No

Appendix A – Proposed Amended Rule 1110.2
Appendix A contains a complete version of Proposed Amended Rule 1110.2.

Appendix B – Assumptions and Calculations
Appendix B contains the assumptions and calculations for Alternatives C and D.

Appendix C – Notice of Preparation / Initial Study
SCAQMD staff previously prepared an initial study (IS) and concluded that an EIR-equivalent CEQA document was warranted. The IS, along with a Notice of Preparation (NOP), was circulated for a 30-day public review period to solicit comments from public agencies and the public in general, on potential impacts from the proposed project. No comment letters were received on the NOP/IS. The NOP/IS is included in Appendix C of this ~~Draft~~Final SEA.

CHAPTER 2

PROJECT DESCRIPTION

PROJECT LOCATION

The proposed project consists of amending Rule 1110.2, which would provide biogas fired engines additional time to comply with the rule's emission limits and limit the number of breakdowns and emissions during breakdown events for all engines. The rule applies to all stationary and portable engines over 50 rated brake horsepower within and throughout the SCAQMD's jurisdiction (e.g., the entire district).

The SCAQMD has jurisdiction over an area of 10,473 square miles, consisting of the four-county South Coast Air Basin (Basin) and the Riverside County portions of the Salton Sea Air Basin (SSAB) and the Mojave Desert Air Basin (MDAB). The Basin, which is a sub area of the SCAQMD's jurisdiction, is bounded by the Pacific Ocean to the west and the San Gabriel, San Bernardino, and San Jacinto Mountains to the north and east. The 6,745 square-mile Basin includes all of Orange County and the non-desert portions of Los Angeles, Riverside, and San Bernardino counties. The Riverside County portions of the SSAB and MDAB are bounded by the San Jacinto Mountains to the west and span eastward up to the Palo Verde Valley. The federal nonattainment area (known as the Coachella Valley Planning Area) is a sub region of both Riverside County and the SSAB and is bounded by the San Jacinto Mountains to the west and the eastern boundary of the Coachella Valley to the east. The SCAQMD's jurisdictional area is depicted in Figure 2-1. The proposed project would be in effect in the entire area of the SCAQMD's jurisdiction.

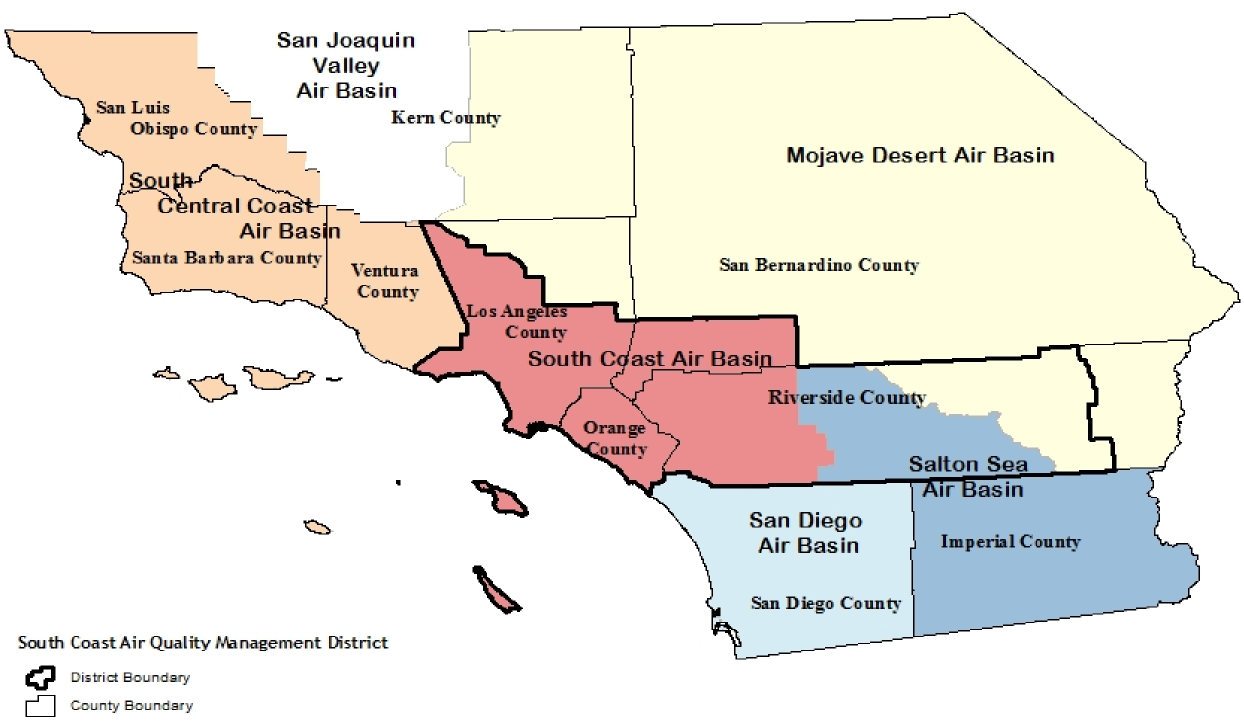

Figure 2-1
South Coast Air Quality Management District Boundaries

PROJECT BACKGROUND

Rule 1110.2 – Emissions from Gaseous- and Liquid-Fired Engines was adopted by the AQMD Governing Board on August 3, 1990. It required that either 1) NOx emissions be reduced over 90% to one of two compliance limits specified by the rule, or; 2) the engines be permanently removed from service or replaced with electric motors. It was amended in September 1990 to clarify rule language and then amended in August and December of 1994 to modify the CO monitoring requirements and to clarify rule language. The amendment of November 1997 eliminated the requirement for continuous monitoring of CO, reduced the source testing requirement from once every year to once every three years, and exempted non-road engines, including portable engines, from most requirements. The amendment in June 2005 made the previously exempt agricultural engines subject to the rule.

To address widespread non-compliance with stationary IC engines, the 2008 amendment augmented the source testing, continuous monitoring, inspection and maintenance (I&M), and reporting requirements of the rule to improve compliance. It also required stationary, non-emergency engines to meet emission standards equivalent to current BACT for NOx and VOC and almost to BACT for CO. This partially implemented the 2007 AQMP control measure for Facility Modernization (MCS-001). Additionally, the 2008 amendment required new electric generating engines to limit emissions to levels nearly equivalent to large central power plants, meeting standards that are at or near the CARB 2007 Distributed Generation Emissions Standards. It also clarified the status for portable engines and set emissions standards for biogas engines to become effective on July 1, 2012 if the July 2010 Technology Assessment would confirm the achievability of those limits.

The 2008 adopting resolution included commitments directing staff to conduct a Technology Assessment to address the availability, feasibility, cost-effectiveness, compliance schedule, and global warming gas impacts of biogas engine control technologies and report back to the Governing Board no later than July 2010. Additionally, the Governing Board directed that the July 2012 biogas emission limits would not be incorporated into the SIP unless the July 2010 Technology Assessment found that the proposed limits are achievable and cost-effective.

The amendment in July 2010 added an exemption to the rule affecting a remote public safety communications site at Santa Rosa Peak in Riverside County which has limited accessibility in the wintertime.

At the July 2010 Governing Board meeting, staff presented an Interim Technology Assessment to address the board resolution commitments in 2008. The Interim Technology Assessment summarized the biogas engine control technologies to date and the status of on-going demonstration projects. Due to the delays caused by the permit moratorium in 2009, the release of a subsequent report was recommended upon the completion of these projects. The Interim Technology Assessment concluded that feasible, cost-effective technology should be available that can support the feasibility of the July 2012 emission limits, but that the delay in the demonstration projects would likely necessitate an adjustment to the July 1, 2012 compliance date of Rule 1110.2.

The September 2012 amendments established a compliance date of January 1, 2016 for biogas engines. A compliance option was also provided so that operators requiring additional time would be given up to two years beyond the compliance date with the submittal of a compliance plan and payment of a compliance flexibility fee. In addition, SCAQMD staff presented an Assessment of Available Technology for Control of NOx, CO, and VOC Emissions from Biogas-Fueled Engines that detailed the different available technologies and demonstration projects for biogas engines, along with costs.

Extension of the Compliance Date for Biogas Engines

Since the amendments to Rule 1110.2 on September 7, 2012, SCAQMD staff has met with the stakeholders periodically, both in public forums and through individual meetings for updates on technology implementation. Based on feedback from these operators, some installations will take longer to install than expected and will reach full compliance after the current deadline of January 1, 2016. The range of implementation dates ranged from about mid-2016 to mid-2018.

On March 31, 2011, the Orange County Sanitation District (OCSD) completed a one year pilot study demonstration of biogas cleanup with oxidation catalyst and SCR. Since that time, the system has continued to meet the future limits of the rule and the operator is currently in the process of retrofitting the remaining engines at its two facilities with the same technology. However, since there is a total of seven engines requiring retrofits, the overall project completion date will be after January 1, 2016. Other operators have similar timelines and have expressed their concerns to SCAQMD staff about meeting the January 1, 2016 deadline.

Two biogas technology demonstration projects are currently underway. One is the NOxTech system at Eastern Municipal Water District's Temecula plant. NOxTech utilizes selective non-catalytic reduction (SNCR) without the necessity for fuel gas pretreatment. Although some preliminary data has shown that the system is capable of reducing NOx from digester gas fueled engines down to 11 ppm, consistent performance is something that the facility is still fine tuning. Based on the results of further testing of this unit, the technology may also be installed at another facility that operates one digester gas engine.

The second technology demonstration project is the hydrogen assisted lean operation (HALO) with partial oxidation gas turbine (POGT), and it is currently underway at the City of San Bernardino Municipal Water Department. This technology employs hydrogen enrichment of the digester gas that results in leaner operation of the engine which reduces NOx emissions. The project has been partially funded with money from the SCAQMD along with the state. The project was awarded to the Gas Technology Institute (GTI) for fabrication and installation. The fabrication and installation has experienced some setbacks which have resulted in delays of the delivery of essential components belonging to the new system. The City of San Bernardino is hoping to use the results of this demonstration project, which will be utilized for only one engine, to possibly retrofit the remaining engines at the facility, which amount to five in total. Given the setbacks and delays, the operators feel that they will have a difficult time implementing the technology by 2016.

Based on the feedback from the regulated facility operators, these projects have not been completed. Thus, SCAQMD staff is proposing to delay implementation to 2017 for non-demonstration projects and 2018 for demonstration projects of the biogas emission limits.

EPA's Ruling on Excess Emissions Due to Breakdowns

~~According to EPA Region IX staff, the current Rule 1110.2 language suggests that sources might be protected from Federal enforcement for even gross emission violations during preventable breakdowns. Under this assessment, the rule language is in contrast to national policy as described in EPA's recent final rule on excess emissions from startup, shutdown, and malfunction on 40 CFR Part 52 (05/22/2015)[1]. The subject rule language originated from the February 2, 2008 amendment. However, EPA Region IX's comments refer to the July 9, 2010 amendment. The inconsistency with the rule language with EPA national policy precludes their ability to fully approve the rule.~~

~~To resolve EPA's issue with potential gross emission violations during preventable breakdowns, corrective actions have been proposed in the context of changes to Rule 1110.2. Not resolving this issue will result in EPA not approving the 2010 amendment into the State Implementation Plan (SIP)[2]. If this disapproval is finalized, sanctions would be imposed unless the U.S. EPA approves subsequent SIP revisions that correct the rule deficiencies within 18 months of disapproval.~~

~~A final disapproval would also trigger the two-year clock for the Federal Implementation Plan (FIP) requirement. It should be noted that the submitted rule has been adopted by the SCAQMD, and U.S. EPA's final limited disapproval would not prevent the SCAQMD from enforcing it.~~

According to EPA Region IX staff, the current Rule 1110.2 language suggests that sources might be protected from enforcement for even gross emission violations during preventable breakdowns. Under this assessment, the current rule language is not consistent with national policy as described in EPA's recent supplemental notice of proposed rulemaking on excess emissions from startup, shutdown, and malfunction (SSM) on 79 FR 55920 (9/17/2014). This final action was finalized on June 12, 2015 (80 FR 33840). The inconsistent Rule 1110.2 language originated in the February 2, 2008 adopted amendment and EPA Region IX's comments refer to this language in the July 9, 2010 amendment. The inconsistency of the rule language with EPA national policy and its final action precludes its ability to fully approve the rule and regulation. In the final action, EPA states that its policy applies to:

> "Entities potentially affected by this action include states, U.S. territories, local authorities and eligible tribes that are currently administering, or may in the future administer, EPA-approved implementation plans ("air agencies")."

Amendments are proposed to Rule 1110.2 to resolve EPA's issue with potential gross emission violations during preventable breakdowns. Failure to resolve this issue will result in EPA's disapproval of the 2010 amendment into the State Implementation Plan (SIP). If this disapproval is finalized, sanctions would be imposed unless the U.S. EPA approves subsequent SIP revisions that correct the rule deficiencies within 18 months of disapproval.

A final disapproval would also trigger the two-year clock for the Federal Implementation Plan (FIP) requirement. It should be noted that the submitted rule has been adopted by the SCAQMD, and U.S. EPA's final disapproval would not prevent the SCAQMD from enforcing it.

PROJECT DESCRIPTION

The proposed project consists of amending Rule 1110.2. The purpose of the proposed project is to provide biogas fired engines additional time to comply with the rule's emission limits and limit the number of breakdowns and resultant excess emissions during breakdown events for all engines. The following is a summary of the key components of PAR 1110.2. A copy of PAR 1110.2 can be found in Appendix A. PAR 1110.2 includes the following:

- Establish an effective date of January 1, 2017 for all biogas engines.
- Provide additional time until January 1, 2018 for non-demonstration project biogas engines with the submittal of a compliance plan and payment of a compliance flexibility fee.
- Provide an alternate compliance option to give two biogas owners or operators that commenced demonstration projects prior to January 1, 2015 additional time until January 1, 2018 without payment of a compliance flexibility fee, and to January 1, 2019 with payment of a compliance flexibility fee.
- Allow the assessment of the compliance flexibility fee on a quarterly basis.
- Address EPA's concerns with equipment breakdowns and potential excess emissions without enforcement by establishing a limit for exceedances due to breakdowns without enforcement action per calendar quarter.
- A proposal for the breakdown provision provided by the affected industries has been included as an alternative rule proposal.

The project would result in a delay of 0.9 tons per day of NOx reductions, 0.5 tons per day of VOC reductions, and 20 tons per day of CO reductions. The cost effectiveness for the installation of controls would remain unchanged from those presented in the 2012 Final Technology Assessment and Final Staff Report.

The following table indicates the NOx, VOC, and CO emission limits and compliance dates for biogas engines:

[1] http://www.epa.gov/airquality/urbanair/sipstatus/emissions.html (Accessed August 31, 2015)

[2] The 2010 Rule 1110.2 amendments were already submitted for SIP approval. In fact, these provisions originated from the 2008 amendment which was submitted and approved into the SIP, except for the biogas emission reductions.

Table 2-1
Proposed Concentration Limits for Biogas Engines

CONCENTRATION LIMITS FOR LANDFILL AND DIGESTER GAS (BIOGAS)-FIRED ENGINES		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 36 x ECF[3] bhp < 500: 45 x ECF[3]	Landfill Gas: 40 Digester Gas: 250 x ECF[3]	2000
CONCENTRATION LIMITS EFFECTIVE JANUARY 1, 2017		
NOx (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250

1 Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

2 Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

3 ECF is the efficiency correction factor.

For operators of biogas engine demonstration projects, the compliance date will be extended to January 1, 2018. A new subparagraph (d)(1)(F) will specify the operators referenced previously who are still undergoing demonstration projects.

> "For the City of San Bernardino and Eastern Municipal Water District that commenced and implemented technology demonstration projects prior to January 1, 2015, all their biogas engines shall have until January 1, 2018 to comply with the requirements of Table III-B of PAR 1110.2."

Since the Draft SEA was released for public review and comment, OCSD staff contacted SCAQMD staff and requested that the OCSD project be classified as a "demonstration project", which gives OCSD an additional year to comply with the requirements of PAR 1110.2. In doing so, the emissions reductions delayed from the OCSD project would shift from 2017 to 2018. Please refer to Chapter 4 for a discussion of the air quality impacts associated with this change.

The January 1, 2017 (non-demonstration project biogas engines) and January 1, 2018 (demonstration project biogas engines) compliance dates referenced above would involve no fee payment for the additional time[3].

[3] The demonstration projects are those that are being tested at EMWD or SBMWD and the technologies are NOxTech, HALO, and Tecogen catalysts. The demonstrated technology is SCR and Oxidation Catalyst with biogas cleanup. Facilities that elect to install SCR, may do so at any time because it is already achieved in practice.

An alternate compliance option is also proposed to provide biogas operators with additional time to comply beyond the compliance dates referenced in proposed Table III-B of PAR 1110.2 and subparagraph (d)(1)(F). The additional time would be provided with the submittal of a compliance plan and compliance flexibility fee. Subdivision (h) outlines the requirements for the plan submittal and the calculation of the compliance flexibility fee. The fee will now be available to be paid in quarterly increments, up to one additional year. Some stakeholders felt that paying for an entire year of fees was excessive, especially if an engine would come into compliance earlier in the year. The fee would now be calculated based on the updated fee rate ($11.75/bhp per quarter) and multiplying by the rated brake horsepower of the unit and then multiplying by the number of quarters to defer (up to four quarters, or one year)[4]. The fees collected from this alternate compliance option will applied to AQMD NOx reduction programs. The proposed amendments will provide biogas engine facilities with additional time to implement the proper controls to meet the emission limits. For non-demonstration project biogas engines, additional time would be provided beyond the January 1, 2017 compliance date in Table III-B of PAR 1110.2 up to January 1, 2018 with payment of the fee. For demonstration project biogas engines designated in (d)(1)(F), additional time would be provided beyond the January 1, 2018 compliance date in (d)(1)(F) up to January 1, 2019 with payment of the fee.

To address the EPA issues relating to unenforced excess emissions from breakdowns, the provisions within the Inspection and Monitoring (I&M) Plan in subparagraph (f)(1)(D) will be amended. The I&M Plan requirements were established in the 2008 amendment to ensure non-CEMS engine compliance with the rule limits between source tests. They include procedures for the monitoring of engine parameters and periodic testing of emissions with a portable analyzer, as well as recordkeeping requirements.

<u>The following additional provisions are also included in the proposed project:</u>

- <u>An alternative rule proposal has been included that would remove rule language stating that breakdowns are not violations, thus subjecting operators to potential federal enforcement action or citizen lawsuits.</u>
- <u>For biogas engines operating until the time of compliance with the limits specified in Table III-B, the emission thresholds for breakdowns that will count towards the incidence limit are 185 ppmv for NOx and 2000 ppmv for CO.</u>
- <u>Diagnostic emission checks would be subject to the current rule provisions for correcting and demonstrating compliance within 24 hours from the time the operator knew of the excess emissions. There is no per calendar quarter limit proposed if emissions are below excess emission thresholds for breakdowns.</u>

~~Clause (f)(1)(D)(v) lists the procedures for responding to, diagnosing, and correcting breakdowns, faults, malfunctions, alarms, emission checks finding emissions in excess of rule or permit limits, and parameters out-of-range. Emission checks performed with a portable analyzer will now be described as diagnostic emission checks. The staff proposal maintains the 24-hour time frame for an owner or operator who uses a portable analyzer as a diagnostic tool for monitoring purposes to correct an exceedance from when it is discovered [subclause (f)(1)(D)(v)(I)]. Notwithstanding~~

[4] The fee is based on the Carl Moyer cost effectiveness of $17,200 per ton and is calculated based on the NOx reductions of PAR 1110.2. The total cost per year is divided by the sum brake horsepower (bhp) of all the affected biogas engines to arrive at $47 per bhp per year ($11.75/bhp per quarter).

~~these requirements, additional requirements are now proposed to comply. In proposed subclause (f)(1)(D)(v)(II),~~

~~"For excess emissions due to breakdowns that result in NOx emissions (corrected to 15% O_2) greater than 45 ppmvd for lean-burn engines and 150 ppmvd for rich-burn engines, or CO emissions (corrected to 15% O_2) greater than 250 ppmvd for lean-burn engines and 2000 ppmvd for rich-burn engines, the operator shall not be considered in violation of this rule if the operator demonstrates the following: (1) compliance with subclause (f)(1)(D)(v)(I), (2) compliance with the reporting requirements of subparagraph (f)(1)(H), and (3) the engine with excess emissions has no more than three incidences of breakdowns in the calendar quarter."If an operator is performing weekly or quarterly diagnostic emission checks with a portable analyzer and finds that the emissions are above the rule limits, the operator shall correct the problem and retest, or shut down the engine by the end of the operating cycle or 24 hours from the time the operator knew of the exceedance. Additionally, the operator shall not be considered in violation of the emission limits if the problem is corrected and a subsequent diagnostic emission check demonstrates compliance.~~

~~However, for breakdowns resulting in emissions in excess of the concentration limits referenced above, the emissions often are of a more serious nature and the staff proposal aims to place a cap on the number of these excursions at no more than three per any calendar quarter. EPA concerns on excess emissions are based on the current rule allowing for correction of a breakdown without penalty and this situation could potentially occur repeatedly, resulting in much more excess emissions. The staff proposal will characterize breakdowns as a new definition in paragraph (c)(3):~~

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

~~An operator with an engine that experiences a breakdown with resultant emissions in the ranges specified above must also comply with the requirements to correct the problem and demonstrate compliance with a subsequent diagnostic emission check, per subclause (f)(1)(D)(v)(I). The staff proposal would now require that these types of incidences be limited to no more than three in any calendar quarter.~~

~~Further clarification of a breakdown is specified in paragraph (c)(3) in that any breakdown, no matter what the resultant excess emissions would be, that is caused by operator neglect, improper operation or improper maintenance procedures would be a violation. All breakdowns, no matter what the cause, are still subject to the current reporting requirements of Rule 1110.2(f)(1)(H).~~

~~Some minor clarifications were added to further specify the requirements of the I&M Plan for engines that operate without CEMS. An engine that operates both NOx and CO CEMS is not subject to the requirements of subparagraph (f)(1)(D), which contain the I&M Plan requirements. Operators with engines that have CEMS have the advantage of monitoring their emissions continuously and would be instantly alerted in the event that something goes wrong with the equipment. Any excess of the emission standard for these engines would be a violation under the current rule.~~

~~There are, however, engines that have a NOx CEMS but do not have a CO CEMS. For example, lean-burn engines typically have inherently lower CO emissions than their rich-burn counterparts~~

~~and are not required to have a CO CEMS as stated in clause (f)(1)(A)(vii) of the current rule. Since these engines have a NOx CEMS, an I&M Plan as it pertains to NOx is not required. However, since these engines are subject to the quarterly CO monitoring requirements of (f)(1)(D)(iii)(II) in the current rule as part of the I&M Plan, clause (f)(1)(D)(xi) clarifies the applicability of these requirements for CO.~~

> ~~"If an engine has a NOx CEMS and does not have a CO CEMS, it is subject to this subparagraph (f)(1)(D) as it pertains to CO only."~~

~~A new clause (f)(1)(D)(x) has also been added to state that an engine operator shall comply with the diagnostic emission check provisions of (f)(1)(D)(iii) regardless of whether an I&M Plan is submitted or approved, pursuant to the requirements of (e)(4) and (e)(6). This clause would require continued diagnostic emission monitoring whether or not a facility has an I&M plan that is invalid or is being processed.~~

PROJECT OBJECTIVES

CEQA Guidelines §15124(b) requires the project description to include a statement of objectives sought by the proposed project, including the underlying purpose of the proposed project. Compatibility with project objectives is one criterion for selecting a range of reasonable project alternatives and provides a standard against which to measure project alternatives. The project objectives identified in the following bullet points have been developed: 1) in compliance with CEQA Guidelines §15124 (b); and, 2) to be consistent with policy objectives of the SCAQMD's New Source Review program. The project objectives are as follows:

- to maintain the lower limits on NOx, VOC, and CO emissions from the combustion of gaseous and liquid biogas engines;
- place biogas engines on a more suitable compliance schedule with achievable emission limitations due to the fact that retrofit construction schedules may extend beyond the current compliance deadline and demonstration project control technologies have not matured in a timely manner for these types of engines;
- to comply with EPA Breakdown provision requirements; and
- aside from temporary air quality impacts, avoid generating any new adverse environmental impacts.

CHAPTER 3

EXISTING SETTING

Introduction

Air Quality and Greenhouse Gases

INTRODUCTION

In order to determine the significance of the impacts associated with a proposed project, it is necessary to evaluate the project's impacts against the backdrop of the environment as it exists at the time the NOP/IS is published. CEQA Guidelines §15360 defines "environment" as "the physical conditions that exist within the area which will be affected by a proposed project including land, air, water, minerals, flora, fauna, ambient noise, and objects of historical or aesthetic significance" (see also Public Resources Code §21060.5). According to CEQA Guidelines §15125 (a), a CEQA document must include a description of the physical environmental conditions in the vicinity of the project, as they exist at the time the NOP is published from both a local and regional perspective. This environmental setting will normally constitute the baseline physical conditions by which a lead agency determines whether an impact is significant. The description of the environmental setting shall be no longer than is necessary to provide an understanding of the significant effects of the proposed project and its alternatives.

The following section summarizes the existing setting for air quality and GHG emissions which is the only environmental topic identified in the NOP/IS (see Appendix C) that may be adversely affected by the proposed project. The Final Program EIR for the 2012 AQMP also contains comprehensive information on existing and projected environmental settings for the topic of air quality and GHG emissions. Copies of the referenced document are available from the SCAQMD's Public Information Center by calling (909) 396-2039.

AIR QUALITY AND GREENHOUSE GASES

This subchapter provides an overview of the existing air quality setting for each criteria pollutant and their precursors, as well as the human health effects resulting from exposure to these pollutants. In addition, this subchapter includes a discussion of non-criteria pollutants such as TACs and GHGs, and climate change.

Criteria Air Pollutants and Identification of Health Effects

It is the responsibility of the SCAQMD to ensure that state and federal ambient air quality standards are achieved and maintained in its geographical jurisdiction. Health-based air quality standards have been established by California and the federal government for the following criteria air pollutants: ozone, carbon monoxide (CO), nitrogen dioxide (NO2), PM10, PM2.5, sulfur dioxide (SO2), and lead. These standards were established to protect sensitive receptors with a margin of safety from adverse health impacts due to exposure to air pollution. The California standards are commonly more stringent than the federal standards and in the case of PM10 and SO2, far more stringent. California has also established standards for sulfates, visibility reducing particles, hydrogen sulfide, and vinyl chloride. SCAQMD also has a general responsibility pursuant to Health & Safety Code (HSC) §41700 to control emissions of air contaminants and prevent endangerment to public health.

Regional Baseline

Air quality in the area of the SCAQMD's jurisdiction has shown substantial improvement over the last three decades. Nevertheless, some federal and state air quality standards are still exceeded frequently and by a wide margin. Of the National Ambient Air Quality Standards (NAAQS) established for seven criteria pollutants (ozone, CO, NO2, PM10, PM2.5, SO2, and lead), the area within the SCAQMD's jurisdiction is only in attainment with CO, SO2, PM10 and the annual NO2 standards. The SCAQMD is designated as unclassifiable/attainment for the hourly NO2 standard. The EPA intends to redesignate areas after sufficient air quality data are available.

Recent air quality data shows the 1997 PM2.5 standard (15 μg/m^3) is being met, but falls short in attaining the 2012 annual PM2.5 standard of 12 μg/m^3. Recent monitoring data also shows that the 2006 24-hour NAAQS for PM2.5 will not be achieved by 2015, due partially to drought conditions and to excessive emissions. The upcoming 2016 AQMP will evaluate PM2.5 emissions and possible control measures to attain the 2006 and 2012 standards by 2019 - 2025. The 2016 AQMP will also demonstrate attainment of the 2008 8-hour ozone standard (75 ppb) by year 2032, and provide an update to the previous 1997 8-hour standard (80 ppb) to be met by 2023. The 2016 AQMP must be submitted to the USEPA by July 20, 2016.

In 2010, a portion of Los Angeles County was designated as not attaining the NAAQS of 0.15 μg/m^3 for lead. SCAQMD identified two large lead-acid battery recycling facilities as possible sources of lead. One of the facilities was the main contributor to the area's nonattainment status. In response to the nonattainment designation, the State submitted the *Final 2012 Lead State Implementation Plan – Los Angeles County* to the USEPA on June 20, 2012. The plan outlines steps that will bring the area into attainment with the standard. As of February 11, 2014, the USEPA announced in the Federal Register (FR) final approval of the lead air quality plan, effective 30 days after publication (e.g., March 12, 2014).

The state and national ambient air quality standards for each of these pollutants and their effects on health are summarized in Table 3-1. The SCAQMD monitors levels of various criteria pollutants at 36 monitoring stations. The 2013 air quality data from SCAQMD's monitoring stations are presented in Table 3-2 for ozone, CO, NO2, PM10, PM2.5, SO2, lead and PM10 sulfate.

Table 3-1

State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	State Standard a)	Federal Primary Standard b)	Most Relevant Effects
Ozone (0_3)	1-hour	0.090 ppm (180 μg/m^3)	No Federal Standard	a) Short-term exposures: 1) Pulmonary function decrements and localized lung edema in humans and animals; and, 2) Risk to public health implied by alterations in pulmonary morphology and host defense in animals; b) Long-term exposures: Risk to public health implied by altered connective tissue metabolism and altered pulmonary morphology in animals after long-term exposures and pulmonary function decrements in chronically exposed humans; c) Vegetation damage; and, d) Property damage.
	8-hour	0.070 ppm (137 μg/m^3)	0.075 ppm (147 μg/m^3)	

Table 3-1 (continued)
State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	State Standard [a)]	Federal Primary Standard [b)]	Most Relevant Effects
Suspended Particulate Matter (PM10)	24-hour	50 μg/m^3	150 μg/m^3	a) Excess deaths from short-term exposures and exacerbation of symptoms in sensitive patients with respiratory disease; and, b) Excess seasonal declines in pulmonary function, especially in children.
	Annual Arithmetic Mean	20 μg/m^3	No Federal Standard	
Fine Particulate Matter (PM2.5)	24-hour	No State Standard	35 μg/m^3 [c)]	a) Increased hospital admissions and emergency room visits for heart and lung disease; b) Increased respiratory symptoms and disease; and, c) Decreased lung functions and premature death.
	Annual Arithmetic Mean	12 μg/m^3	12 μg/m^3	
Carbon Monoxide (CO)	1-Hour	20 ppm (23 mg/m^3)	35 ppm (40 mg/m^3)	a) Aggravation of angina pectoris and other aspects of coronary heart disease; b) Decreased exercise tolerance in persons with peripheral vascular disease and lung disease; c) Impairment of central nervous system functions; and, d) Possible increased risk to fetuses.
	8-Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)	
Nitrogen Dioxide (NO_2)	1-Hour	0.180 ppm (339 μg/m^3)	100 ppb [d)] (188 μg/m^3)	a) Potential to aggravate chronic respiratory disease and respiratory symptoms in sensitive groups; b) Risk to public health implied by pulmonary and extra-pulmonary biochemical and cellular changes and pulmonary structural changes; and, c) Contribution to atmospheric discoloration.
	Annual Arithmetic Mean	0.030 ppm (57 μg/m^3)	0.053 ppm (100 μg/m^3)	
Sulfur Dioxide (SO_2)	1-Hour	0.250 ppm (655 μg/m^3)	75 ppb [e)] (196 μg/m^3)	Broncho-constriction accompanied by symptoms which may include wheezing, shortness of breath and chest tightness, during exercise or physical activity in persons with asthma.
	24-Hour	0.040 ppm (105 μg/m^3)	No Federal Standard	
Sulfate	24-Hour	25 μg/m^3	No Federal Standard	a) Decrease in ventilatory function; b) Aggravation of asthmatic symptoms; c) Aggravation of cardio-pulmonary disease; d) Vegetation damage; e) Degradation of visibility; and, f) Property damage.
Hydrogen Sulfide (H_2S)	1-Hour	0.030 ppm (42 μg/m^3)	No Federal Standard	Odor annoyance.

Table 3-1 (concluded)

State and Federal Ambient Air Quality Standards

Pollutant	Averaging Time	State Standard [a)]	Federal Primary Standard [b)]	Most Relevant Effects
Lead (Pb)	30-Day Average	1.5 $\mu g/m^3$	No Federal Standard	a) Increased body burden; and b) Impairment of blood formation and nerve conduction.
	Rolling 3-Month Average	No State Standard	0.150 $\mu g/m^3$	
Visibility Reducing Particles	8-Hour	Extinction coefficient of 0.23 per kilometer - visibility of ten miles or more due to particles when relative humidity is less than 70 percent.	No Federal Standard	The State standard is a visibility based standard not a health based standard and is intended to limit the frequency and severity of visibility impairment due to regional haze. Nephelometry and AISI Tape Sampler; instrumental measurement on days when relative humidity is less than 70 percent.
Vinyl Chloride	24-Hour	0.010 ppm (26 $\mu g/m^3$)	No Federal Standard	Highly toxic and a known carcinogen that causes a rare cancer of the liver.

a) The California ambient air quality standards for O3, CO, SO2 (1-hour and 24-hour), NO2, PM10, and PM2.5 are values not to be exceeded. All other California standards shown are values not to be equaled or exceeded.

b) The NAAQS, other than O3 and those based on annual averages, are not to be exceeded more than once a year. The O3 standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above the standards is equal to or less than one.

c) The federal 24-hour PM2.5 standard is 35 $\mu g/m^3$ (98th percentile concentration).

d) The federal one-hour NO2 standard is 100 ppb or 0.100 ppm (98th percentile concentration).

e) The federal one-hour SO2 standard is 75 ppb or 0.075 ppm (99th percentile concentration).

KEY: ppb = parts per billion parts of air, by volume; ppm = parts per million parts of air, by volume; $\mu g/m^3$ = micrograms per cubic meter; mg/m^3 = milligrams per cubic meter

Table 3-2
2013 Air Quality Data for SCAQMD

CARBON MONOXIDE (CO) [a]			
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. ppm, 8-hour
LOS ANGELES COUNTY			
1	Central Los Angeles	330	2.0
2	Northwest Coastal Los Angeles County	340	1.3
3	Southwest Coastal Los Angeles County	281*	2.5
4	South Coastal Los Angeles County 1	249*	2.0
4	South Coastal Los Angeles County 2	--	--
4	South Coastal LA County 3	323	2.6
6	West San Fernando Valley	323	2.3
7	East San Fernando Valley	335	2.4
8	West San Gabriel Valley	201*	1.7
9	East San Gabriel Valley 1	343	1.7
9	East San Gabriel Valley 2	347	0.8
10	Pomona/Walnut Valley	340	1.6
11	South San Gabriel Valley	347	2.0
12	South Central Los Angeles County	338	3.5
13	Santa Clarita Valley	352	0.8
ORANGE COUNTY			
16	North Orange County	355	2.2
17	Central Orange County	333	2.6
18	North Coastal Orange County	313	2.0
19	Saddleback Valley	356	1.3
RIVERSIDE COUNTY			
22	Norco/Corona	--	--
23	Metropolitan Riverside County 1	334	2.0
23	Metropolitan Riverside County 2	318	1.6
23	Mira Loma	339	1.9
24	Perris Valley	--	--
25	Lake Elsinore	336	0.6
26	Temecula	--	--
29	Banning Airport	--	--
30	Coachella Valley 1**	354	1.5
30	Coachella Valley 2**	--	--
SAN BERNARDINO COUNTY			
32	Northwest San Bernardino Valley	340	1.7
33	Southwest San Bernardino Valley	--	--
34	Central San Bernardino Valley 1	337	1.3
34	Central San Bernardino Valley 2	340	1.7
35	East San Bernardino Valley	--	--
37	Central San Bernardino Mountains	--	--
38	East San Bernardino Mountains	--	--
DISTRICT MAXIMUM			3.5
SOUTH COAST AIR BASIN			3.5

KEY: ppm = parts per million -- = Pollutant not monitored * Incomplete Data ** Salton Sea Air Basin

[a] The federal 8-hour standard (8-hour average CO > 9 ppm) and state 8-hour standard (8-hour average CO > 9.0 ppm) were not exceeded. The federal and state 1-hour standards (35 ppm and 20 ppm) were not exceeded either.

Table 3-2 (Continued)
2013 Air Quality Data for SCAQMD

OZONE (O_3)										
							No. Days Standard Exceeded			
							Federal		State	
Source Recep Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. in ppm 1-hr	Max. Conc. in ppm 8-hr	Fourth High Conc. ppm 8-hr	Health Advisory ≥ 0.15 ppm 1-hr	Old > 0.124 ppm 1-hr	Current >0.075 ppm 8-hr	Current > 0.09 ppm 1-hr	Current > 0.070 ppm 8-hr
LOS ANGELES COUNTY										
1	Central Los Angeles	365	0.081	0.069	0.060	0	0	0	0	0
2	Northwest Coastal LA County	359	0.088	0.075	0.059	0	0	0	0	1
3	Southwest Coastal LA County	352	0.105	0.081	0.060	0	0	1	1	1
4	South Coastal Los Angeles County 1	267*	0.092	0.070	0.060	0	0	0	0	0
4	South Coastal Los Angeles County 2	--	--	--	--	--	--	--	--	--
4	South Coastal LA County 3	362	0.090	0.069	0.057	0	0	0	0	0
6	West San Fernando Valley	320	0.124	0.092	0.084	0	0	11	7	21
7	East San Fernando Valley	362	0.110	0.083	0.079	0	0	6	4	17
8	West San Gabriel Valley	211*	0.099	0.075	0.070	0	0	0	2	2
9	East San Gabriel Valley 1	361	0.115	0.085	0.080	0	0	6	7	15
9	East San Gabriel Valley 2	340	0.135	0.100	0.088	0	1	24	24	43
10	Pomona/Walnut Valley	355	0.125	0.099	0.085	0	1	15	12	22
11	South San Gabriel Valley	363	0.101	0.072	0.070	0	0	0	2	3
12	South Central Los Angeles County	358	0.090	0.080	0.063	0	0	1	0	1
13	Santa Clarita Valley	365	0.134	0.104	0.094	0	2	40	30	58
ORANGE COUNTY										
16	North Orange County	363	0.104	0.078	0.066	0	0	1	2	2
17	Central Orange County	340	0.084	0.070	0.063	0	0	0	0	0
18	North Coastal Orange County	385	0.095	0.083	0.065	0	0	1	1	2
19	Saddleback Valley	365	0.104	0.082	0.074	0	0	2	2	5
RIVERSIDE COUNTY										
22	Norco/Corona	--	--	--	--	--	--	--	--	--
23	Metropolitan Riverside County 1	357	0.123	0.103	0.094	0	0	26	13	38
23	Metropolitan Riverside County 2	--	--	--	--	--	--	--	--	--
23	Mira Loma	365	0.118	0.096	0.092	0	0	21	11	32
24	Perris Valley	344	0.108	0.090	0.088	0	0	34	17	60
25	Lake Elsinore	362	0.102	0.089	0.081	0	0	12	6	25
26	Temecula	324	0.093	0.078	0.075	0	0	3	0	12
29	Banning Airport	254*	0.115	0.103	0.091	0	0	41	24	66
30	Coachella Valley 1**	365	0.113	0.104	0.090	0	0	46	10	82
30	Coachella Valley 2**	365	0.105	0.087	0.085	0	0	18	2	38
SAN BERNARDINO COUNTY										
32	Northwest San Bernardino Valley	365	0.143	0.111	0.095	0	3	27	25	44
33	Southwest San Bernardino Valley	--	--	--	--	--	--	--	--	--
34	Central San Bernardino Valley 1	363	0.151	0.122	0.100	1	2	42	34	68
34	Central San Bernardino Valley 2	361	0.139	0.112	0.097	0	2	36	22	53
35	East San Bernardino Valley	356	0.133	0.119	0.104	0	3	63	43	93
37	Central San Bernardino Mountains	365	0.120	0.105	0.099	0	0	72	45	101
38	East San Bernardino Mountains	--	--	--	--	--	--	--	--	--
	DISTRICT MAXIMUM		0.151	0.122	0.104	1	3	72	45	101
	SOUTH COAST AIR BASIN		0.151	0.122	0.104	1	5	88	70	119

KEY: ppm = parts per million -- = Pollutant not monitored * Incomplete Data ** Salton Sea Air Basin

Table 3-2 (Continued)
2013 Air Quality Data for SCAQMD

NITROGEN DIOXIDE (NO_2) [b)]					
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	1-hour Max. Conc. ppb	1-hour 98th Percentile Conc. ppb	Annual Average AAM Conc. ppb
LOS ANGELES COUNTY					
1	Central Los Angeles	301	90.3	62.6	21.8
2	Northwest Coastal Los Angeles County	291	51.2	48.8	14.5
3	Southwest Coastal Los Angeles County	334	77.8	58.0	11.8
4	South Coastal Los Angeles County 1	234*	66.9	55.7	14.0
4	South Coastal Los Angeles County 2	--	--	--	--
4	South Coastal LA County 3	325	81.3	71.3	21.5
6	West San Fernando Valley	258*	58.2	51.7	14.4
7	East San Fernando Valley	284	72.5	60.0	20.2
8	West San Gabriel Valley	200*	66.7	60.3	19.1
9	East San Gabriel Valley 1	352	76.9	56.7	17.7
9	East San Gabriel Valley 2	349	55.7	50.4	13.0
10	Pomona/Walnut Valley	343	78.8	64.8	22.5
11	South San Gabriel Valley	337	79.4	60.6	20.6
12	South Central Los Angeles County	340	69.8	61.8	17.6
13	Santa Clarita Valley	362	65.4	45.0	14.4
ORANGE COUNTY					
16	North Orange County	269*	85.0	53.3	14.8
17	Central Orange County	301	81.6	58.8	18.0
18	North Coastal Orange County	330	75.7	53.2	11.6
19	Saddleback Valley	--	--	--	--
RIVERSIDE COUNTY					
22	Norco/Corona	--	--	--	--
23	Metropolitan Riverside County 1	318	59.6	54.8	17.3
23	Metropolitan Riverside County 2	257*	57.6	50.7	15.8
23	Mira Loma	333	53.8	50.7	13.7
24	Perris Valley	--	--	--	--
25	Lake Elsinore	294	46.6	40.0	8.4
26	Temecula	--	--	--	--
29	Banning Airport	308	51.9	45.0	8.5
30	Coachella Valley 1**	359	52.3	38.5	7.5
30	Coachella Valley 2**	--	--	--	--
SAN BERNARDINO COUNTY					
32	Northwest San Bernardino Valley	276*	62.1	53.3	17.7
33	Southwest San Bernardino Valley	--	--	--	--
34	Central San Bernardino Valley 1	335	81.7	60.6	20.6
34	Central San Bernardino Valley 2	291	72.2	54.5	17.6
35	East San Bernardino Valley	--	--	--	--
37	Central San Bernardino Mountains	--	--	--	--
38	East San Bernardino Mountains	--	--	--	--
DISTRICT MAXIMUM			90.3	71.3	22.5
SOUTH COAST AIR BASIN			90.3	71.3	22.5

KEY: ppm = parts per million -- = Pollutant not monitored * Incomplete Data ** Salton Sea Air Basin
ppb = parts per billion AAM = Annual Arithmetic Mean

b) The NO2 federal 1-hour standard is 100 ppb and the annual standard is annual arithmetic mean NO_2 > 0.0534 ppm. The state 1-hour and annual standards are 0.18 ppm (180 ppb) and 0.030 ppm (30 ppb).

Table 3-2 (Continued)
2013 Air Quality Data for SCAQMD

SULFUR DIOXIDE (SO_2) [c]				
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Maximum Conc. ppb, 1-hour	99th Percentile Conc. ppb, 1-hour
LOS ANGELES COUNTY				
1	Central Los Angeles	312	6.3	5.2
2	Northwest Coastal Los Angeles County	--	--	--
3	Southwest Coastal Los Angeles County	322	10.1	6.5
4	South Coastal Los Angeles County 1	178*	21.8	10.1
4	South Coastal Los Angeles County 2	--	--	--
4	South Coastal LA County 3	349	15.1	11.6
6	West San Fernando Valley	--	--	--
7	East San Fernando Valley	342	10.8	4.2
8	West San Gabriel Valley	--	--	--
9	East San Gabriel Valley 1	--	--	--
9	East San Gabriel Valley 2	--	--	--
10	Pomona/Walnut Valley	--	--	--
11	South San Gabriel Valley	--	--	--
12	South Central Los Angeles County	--	--	--
13	Santa Clarita Valley	--	--	--
ORANGE COUNTY				
16	North Orange County	--	--	--
17	Central Orange County	--	--	--
18	North Coastal Orange County	296	4.2	3.3
19	Saddleback Valley	--	--	--
RIVERSIDE COUNTY				
22	Norco/Corona	--	--	--
23	Metropolitan Riverside County 1	354	8.1	4.6
23	Metropolitan Riverside County 2	--	--	--
23	Mira Loma	--	--	--
24	Perris Valley	--	--	--
25	Lake Elsinore	--	--	--
26	Temecula	--	--	--
29	Banning Airport	--	--	--
30	Coachella Valley 1**	--	--	--
30	Coachella Valley 2**	--	--	--
SAN BERNARDINO COUNTY				
32	Northwest San Bernardino Valley	--	--	--
33	Southwest San Bernardino Valley	--	--	--
34	Central San Bernardino Valley 1	298	3.8	3.1
34	Central San Bernardino Valley 2	--	--	--
35	East San Bernardino Valley	--	--	--
37	Central San Bernardino Mountains	--	--	--
38	East San Bernardino Mountains	--	--	--
DISTRICT MAXIMUM			21.8	11.6
SOUTH COAST AIR BASIN			21.8	11.6

KEY: ppm = parts per million -- = Pollutant not monitored * Incomplete Data ** Salton Sea Air Basin
ppb = parts per billion

c) The federal SO2 1-hour standard is 75 ppb (0.075 ppm). The state standards are 1-hour average SO_2 > 0.25 ppm (250 ppb) and 24-hour average SO_2 > 0.04 ppm (40 ppb).

Table 3-2 (Continued)
2013 Air Quality Data for SCAQMD

SUSPENDED PARTICULATE MATTER PM10 d)						
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. µg/m^3, 24-hour	No. (%) Samples Exceeding Standard Federal > 150 µg/m^3, 24-hour	No. (%) Samples Exceeding Standard State > 50 µg/m^3, 24-hour	Annual Average AAM Conc. e) µg/m^3
LOS ANGELES COUNTY						
1	Central Los Angeles	60	57	0	1(2%)	29.5
2	Northwest Coastal Los Angeles County	--	--	--	--	--
3	Southwest Coastal Los Angeles County	56	38	0	0	20.8
4	South Coastal Los Angeles County 1	43*	37	0	0	23.2
4	South Coastal Los Angeles County 2	56	54	0	1(2%)	27.3
4	South Coastal LA County 3	--	--	--	--	--
6	West San Fernando Valley	--	--	--	--	--
7	East San Fernando Valley	58	52	0	1(2%)	28.5
8	West San Gabriel Valley	--	--	--	--	--
9	East San Gabriel Valley 1	61	76	0	6(10%)	33.0
9	East San Gabriel Valley 2	--	--	--	--	--
10	Pomona/Walnut Valley	--	--	--	--	--
11	South San Gabriel Valley	--	--	--	--	--
12	South Central Los Angeles County	--	--	--	--	--
13	Santa Clarita Valley	60	43	0	0	21.6
ORANGE COUNTY						
16	North Orange County	--	--	--	--	--
17	Central Orange County	59	77	0	1(2%)	25.4
18	North Coastal Orange County	--	--	--	--	--
19	Saddleback Valley	61	51	0	1(2%)	19.3
RIVERSIDE COUNTY						
22	Norco/Corona	57	58	0	2(4%)	28.3
23	Metropolitan Riverside County 1	119	135	0	10(8%)	33.8
23	Metropolitan Riverside County 2	--	--	--	--	--
23	Mira Loma	59	147	0	14(24%)	41.1
24	Perris Valley	57	70	0	10(18%)	33.6
25	Lake Elsinore	--	--	--	--	--
26	Temecula	--	--	--	--	--
29	Banning Airport	61	64	0	1(2%)	20.6
30	Coachella Valley 1**	60	129	0	3(5%)	22.6
30	Coachella Valley 2**	120	129 +	0+	23(19%)	38.1
SAN BERNARDINO COUNTY						
32	Northwest San Bernardino Valley	--	--	--	--	--
33	Southwest San Bernardino Valley	60	115	0	3(5%)	33.2
34	Central San Bernardino Valley 1	61	90	0	19(31%)	40.6
34	Central San Bernardino Valley 2	60	102	0	3(5%)	31.3
35	East San Bernardino Valley	61	72	0	2(3%)	27.1
37	Central San Bernardino Mountains	60	37	0	0	21.4
38	East San Bernardino Mountains	--	--	--	--	--
	DISTRICT MAXIMUM		147+	0+	23	41.1
	SOUTH COAST AIR BASIN		147	0	33	41.1

KEY: µg/m^3 = micrograms per cubic meter of air -- = Pollutant not monitored * Incomplete Data ** Salton Sea Air Basin

AAM = Annual Arithmetic Mean + = High PM10 data sample (159 µg/m^3 on August 23, 2013 at Indio) excluded due to the high wind in accordance with the EPA Exceptional Event Regulation. Also, multiple high PM10FEM data recorded in Coachella Valley and the Basin were excluded.

d) Federal Reference Method (FRM) PM10 samples were collected every six days at all sites except for Stations 4144 and 4157, where samples were collected every three days. PM10 statistics listed above are for the FRM data only. Federal Equivalent Method (FEM) PM10 continuous monitoring instruments were operated at some of the above locations. Max 24-hour average PM10 at sites with FEM monitoring was 153 $\mu g/m^3$ at Indio (155 $\mu g/m^3$ is needed to exceed the PM10 standards.

e) Federal annual PM10 standard (AAM > 50 $\mu g/m^3$) was revoked in 2006. State standard is annual average (AAM) > 20 $\mu g/m^3$.

Table 3-2 (Continued)
2013 Air Quality Data for SCAQMD

FINE PARTICULATE MATTER PM2.5 [f)]						
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. µg/m^3, 24-hour	98[th] Percentile Conc. in µg/m^3 24-hr	No. (%) Samples Exceeding Federal Std > 35 µg/m^3, 24-hour	Annual Average AAM Conc. [g)] µg/m^3
LOS ANGELES COUNTY						
1	Central Los Angeles	344	43.1	29.0	1(0.3%)	11.95
2	Northwest Coastal Los Angeles County	--	--	--	--	--
3	Southwest Coastal Los Angeles County	--	--	--	--	--
4	South Coastal Los Angeles County 1	331	47.2	26.1	2(0.6%)	11.34
4	South Coastal Los Angeles County 2	341	42.9	24.6	1(0.3%)	10.97
4	South Coastal LA County 3	--	--	--	--	--
6	West San Fernando Valley	118	41.8	23.0	1(0.8%)	9.71
7	East San Fernando Valley	346	45.1	30.4	4(1.2%)	12.15
8	West San Gabriel Valley	64*	25.7	20.5	0(0%)	10.13
9	East San Gabriel Valley 1	120	29.6	26.4	0(0%)	10.54
9	East San Gabriel Valley 2	--	--	--	--	--
10	Pomona/Walnut Valley	--	--	--	--	--
11	South San Gabriel Valley	114	29.1	28.8	0(0%)	11.56
12	South Central Los Angeles County	113	52.1	24.3	1(0.9%)	11.95
13	Santa Clarita Valley	--	--	--	--	--
ORANGE COUNTY						
16	North Orange County	--	--	--	--	--
17	Central Orange County	331	37.8	22.7	1(0.3%)	10.09
18	North Coastal Orange County	--	--	--	--	--
19	Saddleback Valley	117	28.0	17.5	0(0%)	8.08
RIVERSIDE COUNTY						
22	Norco/Corona	--	--	--	--	--
23	Metropolitan Riverside County 1	353	60.3	34.6	6(1.7%)	12.50
23	Metropolitan Riverside County 2	117	53.7	29.2	1(0.9%)	11.28
23	Mira Loma	355	56.5	37.5	9(2.5%)	14.12
24	Perris Valley	--	--	--	--	--
25	Lake Elsinore	--	--	--	--	--
26	Temecula	--	--	--	--	--
29	Banning Airport	--	--	--	--	--
30	Coachella Valley 1**	117	18.5	13.8	0(0%)	6.52
30	Coachella Valley 2**	118	25.8	15.9	0(0%)	8.35
SAN BERNARDINO COUNTY						
32	Northwest San Bernardino Valley	--	--	--	--	--
33	Southwest San Bernardino Valley	110	49.3	26.8	1(0.9%)	11.98
34	Central San Bernardino Valley 1	121	43.6	33.1	1(0.8%)	12.26
34	Central San Bernardino Valley 2	110	55.3	33.4	1(0.9%)	11.41
35	East San Bernardino Valley	--	--	--	--	--
37	Central San Bernardino Mountains	--	--	--	--	--
38	East San Bernardino Mountains	59	35.5	35.1	1(1.7%)	9.67
DISTRICT MAXIMUM			60.3	37.5	9	14.12
SOUTH COAST AIR BASIN			60.4	37.5	13	14.12

KEY: µg/m3 = micrograms per cubic meter of air -- = Pollutant not monitored * Incomplete Data ** Salton Sea Air Basin
AAM = Annual Arithmetic Mean

f) PM2.5 samples were collected every three days at all sites except for station numbers 069, 072, 077, 087,3176, 4144 and 4165, where samples were taken daily, and station number 5818 where samples were taken every six days. PM10 statistics listed above are for the Federal Reference Method (FRM) data only. Federal Equivalent Method (FEM) PM2.5 continuous monitoring instruments were operated at some of the above locations for special purposes with the max 24-hour average concentration recorded of 83.2 µg/m^3, (at Mira Loma).

g) USEPA has revised the federal annual PM2.5 standard from annual average (AAM) > 15.0 µg/m^3 to 12 µg/m^3, effective March 18, 2013. State standard is annual average (AAM) > 12 µg/m^3.

Table 3-2 (Concluded)
2013 Air Quality Data for SCAQMD

Source Receptor Area No.	Location of Air Monitoring Station	LEAD h) Max. Monthly Average Conc. µg/m³	LEAD h) Max. 3-Months Rolling Averages, µg/m³	PM10 SULFATES i) No. Days of Data	PM10 SULFATES i) Max. Conc. µg/m³, 24-hour
LOS ANGELES COUNTY					
1	Central Los Angeles	0.013	0.011	60	5.8
2	Northwest Coastal Los Angeles County	--	--	--	--
3	Southwest Coastal Los Angeles County	0.005	0.004	56	5.6
4	South Coastal Los Angeles County 1	0.006	0.006	43*	4.5
4	South Coastal Los Angeles County 2	0.012	0.009	56	4.8
4	South Coastal LA County 3	--	--	--	--
6	West San Fernando Valley	--	--	--	--
7	East San Fernando Valley	--	--	58	5.4
8	West San Gabriel Valley	--	--	--	--
9	East San Gabriel Valley 1	--	--	61	4.8
9	East San Gabriel Valley 2	--	--	--	--
10	Pomona/Walnut Valley	--	--	--	--
11	South San Gabriel Valley	0.012	0.011	--	--
12	South Central Los Angeles County	0.014	0.011	--	--
13	Santa Clarita Valley	--	--	60	3.7
ORANGE COUNTY					
16	North Orange County	--	--	--	--
17	Central Orange County	--	--	59	4.7
18	North Coastal Orange County	--	--	--	--
19	Saddleback Valley	--	--	61	4.4
RIVERSIDE COUNTY					
22	Norco/Corona	--	--	57	4.2
23	Metropolitan Riverside County 1	0.010	0.009	119	4.2
23	Metropolitan Riverside County 2	0.007	0.006	--	--
23	Mira Loma	--	--	59	4.2
24	Perris Valley	--	--	57	3.4
25	Lake Elsinore	--	--	--	--
26	Temecula	--	--	--	--
29	Banning Airport	--	--	61	2.9
30	Coachella Valley 1**	--	--	60	3.5
30	Coachella Valley 2**	--	--	120	3.9
SAN BERNARDINO COUNTY					
32	Northwest San Bernardino Valley	0.008	0.006	--	--
33	Southwest San Bernardino Valley	--	--	60	4.8
34	Central San Bernardino Valley 1	--	--	61	4.1
34	Central San Bernardino Valley 2	0.010	0.010	60	4.6
35	East San Bernardino Valley	--	--	61	3.6
37	Central San Bernardino Mountains	--	--	60	3.6
38	East San Bernardino Mountains	--	--	--	--
	DISTRICT MAXIMUM	0.013++	0.011++		5.8
	SOUTH COAST AIR BASIN	0.013++	0.011++		5.8

KEY: µg/m³ = micrograms per cubic meter of air -- = Pollutant not monitored * Incomplete Data ** Salton Sea Air Basin

++ = Higher lead concentrations were recorded at source-oriented monitoring sites immediately downwind of stationary lead sources. Maximum monthly and 3-month rolling averages recorded were 0.14 µg/m³ and 0.10 µg/m³, respectively.

h) Federal lead standard is 3-month rolling average > 0.15 µg/m³; and state standard is monthly average ≥ 1.5 µg/m³. Lead statistics listed above are for population-oriented sites only. Lead standards were not exceeded.

i) State sulfate standard is 24-hour ≥ 25 µg/m³. There is no federal standard for sulfate.

Carbon Monoxide

Carbon monoxide (CO) is a colorless, odorless, relatively inert gas. It is a trace constituent in the unpolluted troposphere, and is produced by both natural processes and human activities. In remote areas far from human habitation, CO occurs in the atmosphere at an average background concentration of 0.04 parts per million (ppm), primarily as a result of natural processes such as forest fires and the oxidation of methane. Global atmospheric mixing of CO from urban and industrial sources creates higher background concentrations (up to 0.20 ppm) near urban areas. The major source of CO in urban areas is incomplete combustion of carbon-containing fuels, mainly gasoline. Approximately 98 percent of the CO emitted into the Basin's atmosphere is from mobile sources. Consequently, CO concentrations are generally highest in the vicinity of major concentrations of vehicular traffic.

CO is a primary pollutant, meaning that it is directly emitted into the air, not formed in the atmosphere by chemical reaction of precursors, as is the case with ozone and other secondary pollutants. Ambient concentrations of CO in the Basin exhibit large spatial and temporal variations due to variations in the rate at which CO is emitted and in the meteorological conditions that govern transport and dilution. Unlike ozone, CO tends to reach high concentrations in the fall and winter months. The highest concentrations frequently occur on weekdays at times consistent with rush hour traffic and late night during the coolest, most stable portion of the day.

Individuals with a deficient blood supply to the heart are the most susceptible to the adverse effects of CO exposure. The effects observed include earlier onset of chest pain with exercise, and electrocardiograph changes indicative of worsening oxygen supply to the heart.

Inhaled CO has no direct toxic effect on the lungs, but exerts its effect on tissues by interfering with oxygen transport by competing with oxygen to combine with hemoglobin present in the blood to form carboxyhemoglobin (COHb). Hence, conditions with an increased demand for oxygen supply can be adversely affected by exposure to CO. Individuals most at risk include patients with diseases involving heart and blood vessels, fetuses (unborn babies), and patients with chronic hypoxemia (oxygen deficiency) as seen in high altitudes.

Reductions in birth weight and impaired neurobehavioral development have been observed in animals chronically exposed to CO resulting in COHb levels similar to those observed in smokers. Recent studies have found increased risks for adverse birth outcomes with exposure to elevated CO levels. These include pre-term births and heart abnormalities.

CO concentrations were measured at 26 locations in the Basin and neighboring Salton Sea Air Basin (SSAB) areas in 2013. Carbon monoxide concentrations did not exceed any of the federal or state standards in 2013. The highest eight-hour average carbon monoxide concentration recorded (3.5 ppm in the South Central Los Angeles County area) was 39 percent of the federal eight-hour carbon monoxide standard of 9.0 ppm. The state eight-hour standard is also 9.0 ppm.

The 2003 AQMP revisions to the SCAQMD's CO Plan served two purposes: 1) it replaced the 1997 attainment demonstration that lapsed at the end of 2000; and, 2) it provided the basis for a CO maintenance plan in the future. In 2004, the SCAQMD formally requested the USEPA to re-designate the Basin from non-attainment to attainment with the CO National Ambient Air Quality Standards. On February 24, 2007, USEPA published in the FR its proposed decision to re-designate the Basin from non-attainment to attainment for CO. The comment period on the re-designation proposal closed on March 16, 2007 with no comments received by the USEPA. On May 11, 2007, USEPA published in the FR its final decision to approve the SCAQMD's request for re-designation from non-attainment to attainment for CO, effective June 11, 2007.

Ozone

Ozone (O3), a colorless gas with a sharp odor, is a highly reactive form of oxygen. High ozone concentrations exist naturally in the stratosphere. Some mixing of stratospheric ozone downward through the troposphere to the earth's surface does occur; however, the extent of ozone transport is limited. At the earth's surface in sites remote from urban areas ozone concentrations are normally very low (e.g., from 0.02 ppm to 0.045 ppm), however recent studies indicate that the 'background' value of ozone may be rising due to the increased influence of pollution from global pollution produced outside of the SCAQMD[3, 4].

While ozone is beneficial in the stratosphere because it filters out skin-cancer-causing ultraviolet radiation, it is a highly reactive oxidant. It is this reactivity which accounts for its damaging effects on materials, plants, and human health at the earth's surface.

The propensity of ozone for reacting with organic materials causes it to be damaging to living cells and ambient ozone concentrations in the Basin are frequently sufficient to cause health effects. Ozone enters the human body primarily through the respiratory tract and causes respiratory irritation and discomfort, makes breathing more difficult during exercise, and reduces the respiratory system's ability to remove inhaled particles and fight infection.

Individuals exercising outdoors, children and people with preexisting lung disease, such as asthma and chronic pulmonary lung disease, are considered to be the most susceptible subgroups for ozone effects. Short-term exposures (lasting for a few hours) to ozone at levels typically observed in southern California can result in breathing pattern changes, reduction of breathing capacity, increased susceptibility to infections, inflammation of the lung tissue, and some immunological changes. In recent years, a correlation between elevated ambient ozone levels and increases in daily hospital admission rates, as well as mortality, has also been reported. An increased risk for asthma has been found in children who participate in multiple sports and live in high ozone communities. Elevated ozone levels are also associated with increased school absences.

Ozone exposure under exercising conditions is known to increase the severity of the abovementioned observed responses. Animal studies suggest that exposures to a combination

[3] Fiore et al, "Background Ozone Over the United States in Summer: Origin, Trend, and Contribution to Pollution Episodes," Journal of Geophysical Research - Atmospheres, Vol. 107 - D15, 2002, pp. ACH 11-1–ACH 11-25. http://onlinelibrary.wiley.com/doi/10.1029/2001JD000982/abstract

[4] R. Vingarzan, "A Review of Surface Ozone Background Levels and Trends," Atmospheric Environment, Volume 38,2004, pp. 3431–3442. http://www.sciencedirect.com/science/article/pii/S1352231004002808

of pollutants which include ozone may be more toxic than exposure to ozone alone. Although lung volume and resistance changes observed after a single exposure diminish with repeated exposures, biochemical and cellular changes appear to persist, which can lead to subsequent lung structural changes.

In 2013, the SCAQMD regularly monitored ozone concentrations at 31 locations in the Basin and SSAB. Maximum ozone concentrations for all areas monitored were below the stage 1 episode level (0.20 ppm). Maximum ozone concentrations in the SSAB areas monitored by the SCAQMD were lower than the maximum values found in the Basin.

In 2013, the maximum ozone concentrations in the Basin continued to exceed federal standards by wide margins. The maximum one-hour ozone concentration was 0.151 ppm and the maximum eight-hour ozone concentration was 0.122 ppm; both were recorded in the Central San Bernardino Valley 1 area. The federal one-hour ozone standard was revoked and replaced by the eight-hour average ozone standard effective June 15, 2005. Effective May 27, 2008, the USEPA revised the federal eight-hour ozone standard from 0.84 ppm to 0.075 ppm. The maximum eight-hour concentration was 163 percent of the current federal standard. The maximum one-hour concentration was 168 percent of the one-hour state ozone standard of 0.09 ppm. The maximum eight-hour concentration was 174 percent of the eight-hour state ozone standard of 0.070 ppm.

<u>Nitrogen Dioxide</u>

Nitrogen Dioxide (NO2) is a reddish-brown gas with a bleach-like odor. Nitric oxide (NO) is a colorless gas, formed from the nitrogen (N2) and oxygen (O2) in air under conditions of high temperature and pressure which are generally present during combustion of fuels; NO reacts rapidly with the oxygen in air to form NO2. NO2 is responsible for the brownish tinge of polluted air. The two gases, NO and NO2, are referred to collectively as NOx. In the presence of sunlight, NO2 reacts to form nitric oxide and an oxygen atom. The oxygen atom can react further to form ozone, via a complex series of chemical reactions involving hydrocarbons. Nitrogen dioxide may also react to form nitric acid (HNO3) which reacts further to form nitrates, components of PM2.5 and PM10.

Population-based studies suggest that an increase in acute respiratory illness, including infections and respiratory symptoms in children (not infants), is associated with long-term exposures to NO2 at levels found in homes with gas stoves, which are higher than ambient levels found in southern California. Increase in resistance to air flow and airway contraction is observed after short-term exposure to NO2 in healthy subjects. Larger decreases in lung functions are observed in individuals with asthma and/or chronic obstructive pulmonary disease (e.g., chronic bronchitis, emphysema) than in healthy individuals, indicating a greater susceptibility of these sub-groups. More recent studies have found associations between NO2 exposures and cardiopulmonary mortality, decreased lung function, respiratory symptoms and emergency room asthma visits.

In animals, exposure to levels of NO2 considerably higher than ambient concentrations results in increased susceptibility to infections, possibly due to the observed changes in cells involved in maintaining immune functions. The severity of lung tissue damage associated with high levels of ozone exposure increases when animals are exposed to a combination of ozone and NO_2.

In 2013, NO_2 concentrations were monitored at 26 locations. No area of the Basin or SSAB exceeded the federal or state standards for nitrogen dioxide. The Basin has not exceeded the federal standard for nitrogen dioxide (0.0534 ppm) since 1991, when the Los Angeles County portion of the Basin recorded the last exceedance of the standard in any county within the U.S.

In 2013, the maximum annual average concentration was 22.5 parts per billion (ppb) recorded in the Pomona/Walnut Valley area. Effective March 20, 2008, CARB revised the nitrogen dioxide one-hour standard from 0.25 ppm (250 ppb) to 0.18 ppm (180 ppb) and established a new annual standard of 0.030 ppm (30 ppb). In addition, USEPA has established a new federal one-hour NO_2 standard of 100 ppb (98th percentile concentration), effective April 7, 2010. The highest one-hour maximum concentration recorded in 2013 (90.3 ppb in Central Los Angeles County area) was 50 percent of the state one-hour standard. The highest one-hour 98th percentile concentration, recorded in 2013 (71.3 ppb in the South Coastal Los Angeles County area near the ports of Los Angeles and Long Beach), was 40 percent of the state one-hour standard and 71 percent of the federal one-hour standard. NO_x emission reductions continue to be necessary because it is a precursor to both ozone and PM ($PM_{2.5}$ and PM_{10}) concentrations.

<u>Sulfur Dioxide</u>

Sulfur dioxide (SO_2) is a colorless gas with a sharp odor. It reacts in the air to form sulfuric acid (H_2SO_4), which contributes to acid precipitation, and sulfates, which are components of PM_{10} and $PM_{2.5}$. Most of the SO_2 emitted into the atmosphere is produced by burning sulfur-containing fuels.

Exposure of a few minutes to low levels of SO_2 can result in airway constriction in some asthmatics. All asthmatics are sensitive to the effects of SO_2. In asthmatics, increase in resistance to air flow, as well as reduction in breathing capacity leading to severe breathing difficulties, is observed after acute higher exposure to SO_2. In contrast, healthy individuals do not exhibit similar acute responses even after exposure to higher concentrations of SO_2.

Animal studies suggest that despite SO_2 being a respiratory irritant, it does not cause substantial lung injury at ambient concentrations. However, very high levels of exposure can cause lung edema (fluid accumulation), lung tissue damage, and sloughing off of cells lining the respiratory tract.

Some population-based studies indicate that the mortality and morbidity effects associated with fine particles show a similar association with ambient SO_2 levels. In these studies, efforts to separate the effects of SO_2 from those of fine particles have not been successful. It is not clear whether the two pollutants act synergistically or one pollutant alone is the predominant factor.

No exceedances of federal or state standards for SO_2 occurred in 2013 at any of the eight monitoring locations. The maximum one-hour SO_2 concentration was 21.8 ppb, as recorded in the South Coastal Los Angeles County 1 area. The USEPA revised the federal sulfur dioxide standard by establishing a new one-hour standard of 0.075 ppm (75 ppb) and revoking the existing annual arithmetic mean (0.03 ppm) and the 24-hour average (0.14 ppm), effective August 2, 2010. The state standards are 0.25 ppm (250 ppb) for the one-hour average and 0.04 ppm (40 ppb) for the 24-hour average. Though SO2 concentrations remain well below the standards, SO2 is a precursor to sulfate, which is a component of fine particulate matter, PM10, and PM2.5. Because historical measurements have consistently showed concentrations to be well below standards, monitoring has been limited to locations within the District that may have higher concentrations and higher potential exposures to the pollutant.

<u>Particulate Matter (PM10 and PM2.5)</u>

Of great concern to public health are the particles small enough to be inhaled into the deepest parts of the lung. Respirable particles (particulate matter less than about 10 micrometers in diameter) can accumulate in the respiratory system and aggravate health problems such as asthma, bronchitis and other lung diseases. Children, the elderly, exercising adults, and those suffering from asthma are especially vulnerable to adverse health effects of PM10 and PM2.5.

A consistent correlation between elevated ambient fine particulate matter (PM10 and PM2.5) levels and an increase in mortality rates, respiratory infections, number and severity of asthma attacks and the number of hospital admissions has been observed in different parts of the U.S. and various areas around the world. Studies have reported an association between long-term exposure to air pollution dominated by fine particles (PM2.5) and increased mortality, reduction in life-span, and an increased mortality from lung cancer.

Daily fluctuations in fine particulate matter concentration levels have also been related to hospital admissions for acute respiratory conditions, to school and kindergarten absences, to a decrease in respiratory function in normal children and to increased medication use in children and adults with asthma. Studies have also shown lung function growth in children is reduced with long-term exposure to particulate matter. In addition to children, the elderly, and people with pre-existing respiratory and/or cardiovascular disease appear to be more susceptible to the effects of PM10 and PM2.5.

The SCAQMD monitored PM10 concentrations at 21 locations in 2013. The federal 24-hour PM10 standard (150 $\mu g/m^3$) was not exceeded at any of the locations monitored in 2013. The federal annual PM10 standard has been revoked, effective 2006. A maximum 24-hour PM10 concentration of 147 $\mu g/m^3$ was recorded in the Mira Loma area and was 98 percent of the federal standard and 294 percent of the much more stringent state 24-hour PM10 standard (50 $\mu g/m^3$). The state 24-hour PM10 standard was exceeded at 17 of the 21 monitoring stations. A maximum annual average PM10 concentration of 41.1 $\mu g/m^3$ was recorded in Mira Loma. The maximum annual average PM10 concentration in Mira Loma was 206 percent of the state standard of 20 $\mu g/m^3$. The USEPA published approval of SCAQMD's PM10 request for redesignation for attainment on June 26, 2013, with an implementation date of July 26, 2013.

In 2013, PM2.5 concentrations were monitored at 20 locations throughout the district. USEPA revised the federal 24-hour PM2.5 standard from 65 $\mu g/m^3$ to 35 $\mu g/m^3$, effective December 17, 2006, and retained the form of the standard using the 98th percentile each year, averaged over three years. In 2013, the 98th percentile PM2.5 concentrations in the Basin exceeded the current federal 24-hour PM2.5 standard in two of the 20 locations. A 98th percentile 24-hour PM2.5 concentration of 37.5 µg/m^3 was recorded in the Metropolitan Riverside County 1 area, which represents 107 percent of the federal standard of 35 µg/m^3. Further, in July 2015, SCAQMD staff submitted a letter to EPA requesting a change in its attainment status to 'Serious' non-attainment due to high 24-hour concentrations of PM2.5 persisting through 2015. A maximum annual average PM2.5 concentration of 14.12 µg/m^3 was recorded in Mira Loma, which represents 118 percent of both the federal and state standard of 12 µg/m^3.

Similar to PM10 concentrations, PM2.5 concentrations were higher in the inland valley areas of San Bernardino and Metropolitan Riverside counties. However, PM2.5 concentrations were also high in Central Los Angeles County and the East San Gabriel Valley. The high PM2.5 concentrations in Los Angeles County are mainly due to the secondary formation of smaller particulates resulting from mobile and stationary source activities. In contrast to PM10, PM2.5 concentrations were low in the Coachella Valley area of SSAB. PM10 concentrations are normally higher in the desert areas due to windblown and fugitive dust emissions.

<u>Lead</u>

Under the federal Clean Air Act, lead is classified as a "criteria pollutant." Lead has observed adverse health effects at ambient concentrations. Lead is also deemed a carcinogenic toxic air contaminant (TAC) by the Office of Environmental Health Hazard Assessment (OEHHA). The USEPA has thoroughly reviewed the lead exposure and health effects research, and has prepared substantial documentation in the form of a Criteria Document to support the selection of the 2008 NAAQS for lead. The Criteria Document used for the development of the 2008 NAAQS for lead states that studies and evidence strongly substantiate that blood lead levels in a range of 5-10 µg/dL, or possibly lower, could likely result in neurocognitive effects in children. The report further states that "there is no level of lead exposure that can yet be identified with confidence, as clearly not being associated with some risk of deleterious health effects[5]."

Fetuses, infants, and children are more sensitive than others to the adverse effects of lead exposure. Exposure to low levels of lead can adversely affect the development and function of the central nervous system, leading to learning disorders, distractibility, inability to follow simple commands, and lower intelligence quotient. In adults, increased lead levels are associated with increased blood pressure. Chronic health effects include nervous and reproductive system disorders, neurological and respiratory damage, cognitive and behavioral changes, and hypertension. Exposure to lead can also potentially increase the risk of contracting cancer or result in other adverse health effects. Lead has been classified as a probable human carcinogen by the International Agency for Research on Cancer, based mainly on sufficient animal evidence, and as reasonably anticipated to be a human carcinogen by the U.S. National Toxicology Program. Young children are especially susceptible to the effects of environmental lead because their bodies accumulate lead more readily than do those of adults, and because they are more

[5] Environmental Protection Agency, Office of Research and Development, "Air Quality Criteria Document for Lead, Volumes I-II," October 2006.

vulnerable to certain biological effects of lead including learning disabilities, behavioral problems, and deficits in IQ.

Lead poisoning can cause anemia, lethargy, seizures, and death. Lead can be stored in the bone from early-age environmental exposure, and elevated blood lead levels can occur due to breakdown of bone tissue during pregnancy, hyperthyroidism (increased secretion of hormones from the thyroid gland), and osteoporosis (breakdown of bone tissue). Fetuses and breast-fed babies can be exposed to higher levels of lead because of previous environmental lead exposure of their mothers.

Lead in the atmosphere is present as a mixture of a number of lead compounds. Leaded fuels and lead smelters have traditionally been the main sources of lead emitted into the air. Due to the phasing out of leaded fuels, there was a dramatic reduction in atmospheric lead in the Basin over the past three decades.

As a result, the federal and current state standards for lead were not exceeded in any area of the district in 2013. There have been no violations of these standards at the SCAQMD's regular air monitoring stations since 1982, as a result of removal of lead from fuels.

On November 12, 2008, USEPA published new NAAQS for lead, which became effective January 12, 2010. The existing national lead standard, 1.5 $\mu g/m^3$, was reduced to 0.15 $\mu g/m^3$, averaged over a rolling three-month period.

The maximum 3-month rolling average lead concentration (0.011 $\mu g/m^3$ was recorded at monitoring stations in Central Los Angeles, South San Gabriel Valley, and South Central LA County areas) was seven percent of the federal 3-month rolling lead standard (0.15 $\mu g/m^3$). The maximum monthly average lead concentration (0.014 $\mu g/m^3$ in South Central Los Angeles County area), measured at special monitoring sites immediately adjacent to stationary sources of lead was 0.9 percent of the state monthly average lead standard (1.5 $\mu g/m^3$). No lead data were obtained at SSAB and Orange County stations in 2013. Because historical lead data showed concentrations in SSAB and Orange County areas to be well below the standard, measurements have been discontinued at these locations.

In 2010, a portion of Los Angeles County was designated as not attaining the NAAQS of 0.15 $\mu g/m^3$ for lead based on monitored air quality data from 2007 to 2009 that indicated a violation of the NAAQS near and due to one of two large lead-acid battery recycling facilities in the District. However, the new federal standard was not exceeded at any source/receptor location the following year (in 2011).

Nevertheless, based on the monitored emissions from the two battery recycling facilities, USEPA designated the Los Angeles County portion of the Basin as non-attainment for the new lead standard, effective December 31, 2010. In response to the new federal lead standard, the SCAQMD adopted Rule 1420.1 – Emissions Standard for Lead from Large Lead-Acid Battery Recycling Facilities, in November 2010, to ensure that lead emissions do not exceed the new federal standard.

In response to the nonattainment designation, the State submitted the *Final 2012 Lead State Implementation Plan – Los Angeles County* (2012 Lead SIP) to the USEPA on June 20, 2012.

The plan outlines steps that will bring the area into attainment with the federal lead standard before December 31, 2015. As of February 11, 2014, the USEPA announced in the Federal Register (FR) final approval of the lead air quality plan, to be effective 30 days after publication (e.g., March 12, 2014).

In 2013, higher lead concentrations continued to be recorded at source-oriented monitoring sites immediately downwind of stationary lead sources. The maximum monthly and 3-month rolling averages recorded in 2013 were 0.14 $\mu g/m^3$ and 0.10 $\mu g/m^3$, respectively.

In May 2014, the USEPA released its "Policy Assessment for the Review of the Lead National Ambient Air Quality Standards," reaffirming the primary (health-based) and secondary (welfare-based) staff conclusions regarding whether to retain the current standards. In January 2015, the USEPA announced that the ambient lead concentration standard of 0.15 $\mu g/m^3$ averaged over a rolling 3-month period would remain unchanged. The 90-day comment period for this proposal ended on April 6, 2015 and requires further action by the USEPA.

To continue to pursue reducing lead emissions from large lead-acid battery recycling facilities, in March 2015, Rule 1420.1 was amended to further lower the ambient lead concentration limit to 0.120 $\mu g/m^3$ effective January 1, 2016 and 0.100 $\mu g/m^3$ effective January 1, 2017 and the point source lead emission rate to 0.023 pounds per hour, as well as adding additional housekeeping and maintenance requirements.

On April 7, 2015, the larger of the two lead-acid battery recycling facilities withdrew its California Department of Toxic Substance Control (DTSC) permit application and provided notification of its intent to permanently close.

While Rule 1420.1 will be effective in reducing emissions from the large lead-acid battery recycling industry, lead emissions from the broader industry source category of metal melting is still a concern because the metal melting industry is the most significant stationary source of reported lead emissions. While existing federal and state regulations currently control lead emissions from the metal melting industry, additional requirements similar to those that have effectively reduced emissions from large lead-acid battery recyclers are also necessary to adequately protect public health by minimizing public exposure to lead emissions and preventing exceedances of the lead NAAQS in the Basin. As a result, the SCAQMD is proposing to adopt Rule 1420.2 – Emission Standards for Lead from Metal Melting Facilities which is scheduled to be considered by the SCAQMD Governing Board at its September 4, 2015 public hearing.

Sulfates

Sulfates (SOx) are chemical compounds which contain the sulfate ion and are part of the mixture of solid materials which make up PM10. Most of the sulfates in the atmosphere are produced by oxidation of SO2. Oxidation of sulfur dioxide yields sulfur trioxide (SO3) which reacts with water to form sulfuric acid, which contributes to acid deposition. The reaction of sulfuric acid with basic substances such as ammonia yields sulfates, a component of PM10 and PM2.5.

Most of the health effects associated with fine particles and SO2 at ambient levels are also associated with SOx. Thus, both mortality and morbidity effects have been observed with an increase in ambient SOx concentrations. However, efforts to separate the effects of SOx from the effects of other pollutants have generally not been successful.

Clinical studies of asthmatics exposed to sulfuric acid suggest that adolescent asthmatics are possibly a subgroup susceptible to acid aerosol exposure. Animal studies suggest that acidic particles such as sulfuric acid aerosol and ammonium bisulfate are more toxic than non-acidic particles like ammonium sulfate. Whether the effects are attributable to acidity or to particles remains unresolved.

In 2013, the state 24-hour sulfate standard (25 $\mu g/m^3$) was not exceeded in any of the monitoring locations in the district. There is no federal sulfate standard.

Hydrogen Sulfide

Hydrogen Sulfide (H2S) is a colorless gas with the characteristic foul odor of rotten eggs. H2S is heavier than air, very poisonous, corrosive, flammable, and explosive. H2S is naturally occurring in crude oil and natural gas, but H2S can also be created from the bacterial breakdown of organic matter in the absence of oxygen (e.g., in swamps and sewers). For example, on September 9, 2012, a thunderstorm over the Salton Sea caused odors to be released across the Coachella Valley. The SCAQMD received over 235 complaints of sulfur and rotten egg type odors in response to this natural event. Air samples were taken at several locations around the Salton Sea area to confirm source of odors and results of sampling showed total sulfur gas concentration of 149 ppb. The State air quality standard for H2S is 30 ppb, averaged over one-hour, and the odor threshold for H2S is approximately eight ppb. In response to potential for increasing odor complaints in the future, in October 2013, the SCAQMD installed two H2S monitors in the Coachella Valley to monitor the presence of H2S during odor events at the Salton Sea. The monitors are located at Saul Martinez Elementary School in Mecca and on the Torres Martinez Desert Cahuilla Indian Tribal land near the north end of the Salton Sea.

Vinyl Chloride

Vinyl chloride is a colorless, flammable gas at ambient temperature and pressure. It is also highly toxic and is classified as a carcinogen by the state Office of Environmental Health Hazard Assessment (OEHHA), in addition to the designations by the American Conference of Governmental Industrial Hygienists (confirmed carcinogen in humans) and by the International Agency for Research on Cancer (known to be a human carcinogen). At room temperature, vinyl chloride is a gas with a sickly sweet odor that is easily condensed. However, it is stored as a liquid. Due to the hazardous nature of vinyl chloride to human health there are no end products that use vinyl chloride in its monomer form. Vinyl chloride is a chemical intermediate, not a final product. It is an important industrial chemical chiefly used to produce the polymer polyvinyl chloride (PVC). The process involves vinyl chloride liquid fed to polymerization reactors where it is converted from a monomer to a polymer PVC. The final product of the polymerization process is PVC in either a flake or pellet form. Billions of pounds of PVC are sold on the global market each year. From its flake or pellet form, PVC is sold to companies that heat and mold the PVC into end products such as PVC pipe and bottles.

In the past, vinyl chloride emissions have been associated primarily with sources such as landfills. Risks from exposure to vinyl chloride are considered to be a localized impacts rather than regional impacts. Because landfills in the district are subject to SCAQMD 1150.1 – Control of Gaseous Emissions from Municipal Solid Waste Landfills, which contains stringent requirements for landfill gas collection and control, potential vinyl chloride emissions are below the level of detection. Therefore, the SCAQMD does not monitor for vinyl chloride at its monitoring stations.

<u>Volatile Organic Compounds</u>

It should be noted that there are no state or national ambient air quality standards for volatile organic compounds (VOCs) because they are not classified as criteria pollutants. VOCs are regulated, however, because limiting VOC emissions reduces the rate of photochemical reactions that contribute to the formation of O3, which is a criteria pollutant. VOCs are also transformed into organic aerosols in the atmosphere, contributing to higher PM10 and lower visibility levels.

Although health-based standards have not been established for VOCs, health effects can occur from exposures to high concentrations of VOCs because of interference with oxygen uptake. In general, ambient VOC concentrations in the atmosphere are suspected to cause coughing, sneezing, headaches, weakness, laryngitis, and bronchitis, even at low concentrations. Some hydrocarbon components classified as VOC emissions are thought or known to be hazardous. Benzene, for example, one hydrocarbon component of VOC emissions, is known to be a human carcinogen.

<u>Visibility</u>

In 2005, annual average visibility at Rubidoux (Riverside), the worst case, was just over 10 miles. With the exception of Lake County, which is designated in attainment, all of the air districts in California are currently designated as unclassified with respect to the CAAQS for visibility reducing particles.

In Class-I wilderness areas, which typically have visual range measured in tens of miles the deciview metric is used to estimate an individual's perception of visibility. The deciview index works inversely to visual range which is measured in miles or kilometers whereby a lower deciview is optimal. In the South Coast Air Basin, the Class-I areas are typically restricted to higher elevations (greater than 6,000 feet above sea level) or far downwind of the metropolitan emission source areas. Visibility in these areas is typically unrestricted due to regional haze despite being in close proximity to the urban setting. The 2005 baseline deciview mapping of the Basin is presented in Figure 3-1. All of the Class-I wilderness areas reside in areas having average deciview values less than 20 with many portions of those areas having average deciview values less than 10. By contrast, Rubidoux, in the Basin has a deciview value exceeding 30.

Federal Regional Haze Rule: The federal Regional Haze Rule, established by the USEPA pursuant to CAA §169A establishes the national goal to prevent future and remedy existing impairment of visibility in federal Class I areas (such as federal wilderness areas and national parks). USEPA's visibility regulations (40 CFR Parts 51.300 - 51.309), require states to develop measures necessary to make reasonable progress towards remedying visibility impairment in these federal Class I areas. CAA §169A and USEPA's visibility regulations also require Best Available Retrofit Technology (BART) for certain large stationary sources that were put in place between 1962 and 1977. (See Regional Haze Regulations and Guidelines for BART Determinations, 70 FR 39104, July 6, 2005).

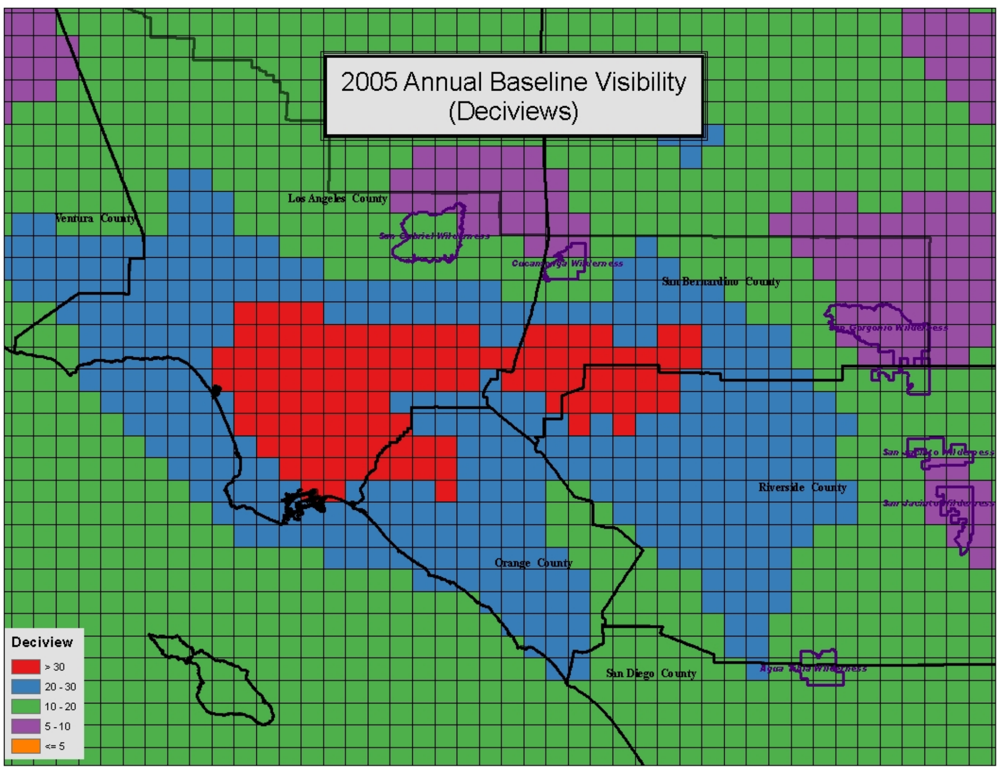

Figure 3-1
2005 Annual Baseline Visibility

California Air Resources Board: Since deterioration of visibility is one of the most obvious manifestations of air pollution and plays a major role in the public's perception of air quality, the state of California has adopted a standard for visibility or visual range. Until 1989, the standard was based on visibility estimates made by human observers. The standard was changed to require measurement of visual range using instruments that measure light scattering and absorption by suspended particles.

The visibility standard is based on the distance that atmospheric conditions allow a person to see at a given time and location. Visibility reduction from air pollution is often due to the presence of sulfur and nitrogen oxides, as well as particulate matter. Visibility degradation occurs when visibility reducing particles are produced in sufficient amounts such that the extinction coefficient is greater than 0.23 inverse kilometers (to reduce the visual range to less than 10 miles) at relative humidity less than 70 percent, 8-hour average (from 10:00 a.m. to 6:00 p.m.) according to the state standard. Future-year visibility in the Basin is projected empirically using the results derived from a regression analysis of visibility with air quality measurements. The regression data set consisted of aerosol composition data collected during a special monitoring program conducted concurrently with visibility data collection (prevailing visibility observations from airports and visibility measurements from district monitoring stations). A full description of the visibility analysis is given in Appendix V of the 2012 AQMP.

With future year reductions of PM2.5 from implementation of all proposed emission controls for 2015, the annual average visibility would improve from 10 miles (calculated for 2008) to over 20 miles at Rubidoux, for example. Visual range in 2021 at all other Basin sites is expected to equal or exceed the Rubidoux visual range. Visual range is expected to double from the 2008 baseline due to reductions of secondary PM2.5, directly emitted PM2.5 (including diesel soot) and lower NO2 concentrations as a result of 2007 AQMP controls.

To meet Federal Regional Haze Rule requirements, CARB adopted the California Regional Haze Plan on January 22, 2009, addressing California's visibility goals through 2018. As shown in Table 3.2-1, California's statewide standard (applicable outside of the Lake Tahoe area) for Visibility Reducing Particles is an extinction coefficient of 0.23 per kilometer over an 8-hour averaging period. This translates to visibility of ten miles or more due to particles when relative humidity is less than 70 percent.

Non-Criteria Pollutants

Although the SCAQMD's primary mandate is attaining the State and National Ambient Air Quality Standards for criteria pollutants within the district, SCAQMD also has a general responsibility pursuant to HSC §41700 to control emissions of air contaminants and prevent endangerment to public health. Additionally, state law requires the SCAQMD to implement airborne toxic control measures (ATCM) adopted by CARB, and to implement the Air Toxics "Hot Spots" Act. As a result, the SCAQMD has regulated pollutants other than criteria pollutants such as TACs, greenhouse gases and stratospheric ozone depleting compounds. The SCAQMD has developed a number of rules to control non-criteria pollutants from both new and existing sources. These rules originated through state directives, CAA requirements, or the SCAQMD rulemaking process.

In addition to promulgating non-criteria pollutant rules, the SCAQMD has been evaluating AQMP control measures as well as existing rules to determine whether or not they would affect, either positively or negatively, emissions of non-criteria pollutants. For example, rules in which VOC components of coating materials are replaced by a non-photochemically reactive chlorinated substance would reduce the impacts resulting from ozone formation, but could increase emissions of toxic compounds or other substances that may have adverse impacts on human health.

The following subsections summarize the existing setting for the two major categories of non-criteria pollutants: compounds that contribute to TACs, global climate change, and stratospheric ozone depletion.

Air Quality – Toxic Air Contaminants

Federal

Under the CAA §112, the USEPA is required to regulate sources that emit one or more of the 187 federally listed hazardous air pollutants (HAPs). HAPs are air toxic pollutants identified in the CAA, which are known or suspected of causing cancer or other serious health effects. The federal HAPs are listed on the USEPA website at http://www.epa.gov/ttn/atw/orig189.html. In order to implement the CAA, approximately 100 National Emission Standards for Hazardous Air Pollutants (NESHAPs) have been promulgated by USEPA for major sources (sources emitting greater than 10 tons per year of a single HAP or greater than 25 tons per year of multiple HAPs). The SCAQMD can either directly implement NESHAPs or adopt rules that contain requirements at least as stringent as the NESHAP requirements. However, since NESHAPs often apply to sources in the district that are already controlled by state-mandated air toxics control measures or by local district rules, many of the sources that would have been subject to federal requirements already comply.

In addition to the major source NESHAPs, USEPA has also controlled HAPs from urban areas by developing Area Source NESHAPs under their Urban Air Toxics Strategy. USEPA defines an area source as a source that emits less than 10 tons annually of any single hazardous air pollutant or less than 25 tons annually of a combination of hazardous air pollutants. The CAA requires the USEPA to identify a list of at least 30 air toxics that pose the greatest potential health threat in urban areas. USEPA is further required to identify and establish a list of area source categories that represent 90 percent of the emissions of the 30 urban air toxics associated with area sources, for which Area Source NESHAPs are to be developed under the CAA. USEPA has identified a total of 70 area source categories with regulations promulgated for more than 30 categories so far.

The federal toxics program recognizes diesel engine exhaust as a health hazard, however, diesel particulate matter itself is not one of their listed toxic air contaminants (TACs). Rather, each toxic compound in the speciated list of compounds in exhaust is considered separately. Although there are no specific NESHAP regulations for diesel PM, diesel particulate emission reductions are realized through federal regulations including diesel fuel standards and emission standards for stationary, marine, and locomotive engines; and idling controls for locomotives.

State

The California air toxics program was based on the CAA and the original federal list of hazardous air pollutants. The state program was established in 1983 under the Toxic Air Contaminant (TAC) Identification and Control Act, Assembly Bill (AB) 1807, Tanner. Under the state program, TACs are identified through a two-step process of risk identification and risk management. This two-step process was designed to protect residents from the health effects of toxic substances in the air.

Control of TACs under the TAC Identification and Control Program: California's TAC identification and control program, adopted in 1983 as AB 1807, is a two-step program in which substances are identified as TACs, and air toxic control measures (ATCMs) are adopted to control emissions from specific sources. CARB has adopted a regulation designating all 187 federal HAPs as TACs.

ATCMs are developed by CARB and implemented by the SCAQMD and other air districts through direct implementation or the adoption of regulations of equal or greater stringency. Generally, the ATCMs reduce emissions to achieve exposure levels below a determined health threshold. If no such threshold levels are determined, emissions are reduced to the lowest level achievable through the best available control technology unless it is determined that an alternative level of emission reduction is adequate to protect public health.

Under California law, a federal NESHAP automatically becomes a state ATCM, unless CARB has already adopted an ATCM for the source category. Once a NESHAP becomes an ATCM, CARB and each air pollution control or air quality management district have certain responsibilities related to adoption or implementation and enforcement of the NESHAP/ATCM.

Control of TACs under the Air Toxics "Hot Spots" Act: The Air Toxics Hot Spots Information and Assessment Act of 1987 (AB 2588) establishes a state-wide program to inventory and assess the risks from facilities that emit TACs and to notify the public about significant health risks associated with the emissions. Facilities are phased into the AB 2588 program based on their emissions of criteria pollutants or their occurrence on lists of toxic emitters compiled by the SCAQMD. Phase I consists of facilities that emit over 25 tons per year of any criteria pollutant and facilities present on the SCAQMD's toxics list. Phase I facilities entered the program by reporting their air TAC emissions for calendar year 1989. Phase II consists of facilities that emit between 10 and 25 tons per year of any criteria pollutant, and submitted air toxic inventory reports for calendar year 1990 emissions. Phase III consists of certain designated types of facilities which emit less than 10 tons per year of any criteria pollutant, and submitted inventory reports for calendar year 1991 emissions. Inventory reports are required to be updated every four years under the state law.

Air Toxics Control Measures: As part of its risk management efforts, CARB has passed state ATCMs to address air toxics from mobile and stationary sources. Some key ATCMs for stationary sources include reductions of benzene emissions from service stations, hexavalent chromium emissions from chrome plating, perchloroethylene emissions from dry cleaning, ethylene oxide emissions from sterilizers, and multiple air toxics from the automotive painting and repair industries.

Many of CARB's recent ATCMs are part of the CARB Risk Reduction Plan to Reduce Particulate Matter Emissions from Diesel-Fueled Engines and Vehicles (DRRP) which was adopted in September 2000 (http://www.arb.ca.gov/diesel/documents/rrpapp.htm) with the goal of reducing diesel particulate matter emissions from compression ignition engines and associated health risk by 75 percent by 2010 and 85 percent by 2020. The DRRP includes strategies to reduce emissions from new and existing engines through the use of ultra-low sulfur diesel fuel, add-on controls, and engine replacement. In addition to stationary source engines, the plan addresses diesel PM emissions from mobile sources such as trucks, buses, construction equipment, locomotives, and ships.

<u>SCAQMD</u>

SCAQMD has regulated criteria air pollutants using either a technology-based or an emissions limit approach. The technology-based approach defines specific control technologies that may be installed to reduce pollutant emissions. The emission limit approach establishes an emission limit, and allows industry to use any emission control equipment, as long as the emission requirements are met. The regulation of TACs often uses a health risk-based approach, but may also require a regulatory approach similar to criteria pollutants, as explained in the following subsections.

Rules and Regulations: Under the SCAQMD's toxic regulatory program there are 15 source-specific rules that target toxic emission reductions that regulate over 10,000 sources such as metal finishing, spraying operations, dry cleaners, film cleaning, gasoline dispensing, and diesel-fueled stationary engines to name a few. In addition, other source-specific rules targeting criteria pollutant reductions also reduce toxic emissions, such as SCAQMD Rule 461 – Gasoline Transfer and Dispensing, which reduces benzene emissions from gasoline dispensing and SCAQMD Rule 1124 – Aerospace Assembly and Component Manufacturing Operations, which reduces perchloroethylene, trichloroethylene, and methylene chloride emissions from aerospace operations.

New and modified sources of TACs in the district are subject to SCAQMD Rule 1401 - New Source Review of Toxic Air Contaminants and SCAQMD Rule 212 - Standards for Approving Permits. Rule 212 requires notification of the SCAQMD's intent to grant a permit to construct a significant project, defined as a new or modified permit unit located within 1000 feet of a school (a state law requirement under AB 3205), a new or modified permit unit posing an maximum individual cancer risk of one in one million (1×10^{-6}) or greater, or a new or modified facility with criteria pollutant emissions exceeding specified daily maximums. Distribution of notice is required to all addresses within a 1/4-mile radius, or other area deemed appropriate by the SCAQMD. Rule 1401 currently controls emissions of carcinogenic and non-carcinogenic (health effects other than cancer) air contaminants from new, modified and relocated sources by specifying limits on cancer risk and hazard index (explained further in the following discussion), respectively. Rule 1401 lists nearly 300 TACs that are evaluated during the SCAQMD's permitting process for new, modified or relocated sources. During the past decade, more than 80 compounds have been added or had risk values amended. The addition of diesel particulate matter from diesel-fueled internal combustion engines as a TAC in March 2008 was one of the most substantial amendments to the rule. SCAQMD Rule 1401.1 – Requirements for New and Relocated Facilities Near Schools, sets risk thresholds for new and relocated facilities near schools. The requirements are more stringent than those for other air toxics rules in order to provide additional protection to school children.

Air Toxics Control Plan: In March 2000, the SCAQMD Governing Board approved the Air Toxics Control Plan (ATCP) which was the first comprehensive plan in the nation to guide future toxic rulemaking and programs. The ATCP was developed to lay out the SCAQMD's air toxics control program which built upon existing federal, state, and local toxic control programs as well as co-benefits from implementation of State Implementation Plan (SIP) measures. The concept for the plan was an outgrowth of the Environmental Justice principles and the Environmental Justice Initiatives adopted by the SCAQMD Governing Board in October 1997. Monitoring studies and air toxics regulations that were created from these initiatives emphasized the need for a more systematic approach to reducing TACs. The intent of the plan was to reduce exposure to air toxics in an equitable and cost-effective manner that promotes clean, healthful air in the district. The plan proposed control strategies to reduce TACs in the district implemented between years 2000 and 2010 through cooperative efforts of the SCAQMD, local governments, CARB and USEPA.

2003 Cumulative Impact Reduction Strategies: The SCAQMD Governing Board approved a cumulative impacts reduction strategy in September 2003. The resulting 25 cumulative impacts strategies were a key element of the 2004 Addendum to the ATCP (see next section). The strategies included rules, policies, funding, education, and cooperation with other agencies. Some of the key SCAQMD accomplishments related to the cumulative impacts reduction strategies were:

- SCAQMD Rule 1401.1 - Requirements for New and Relocated Facilities Near Schools. which set more stringent health risk requirements for new and relocated facilities near schools
- SCAQMD Rule 1470 – Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines, which established diesel PM emission limits and other requirements for diesel-fueled engines
- SCAQMD Rule 1469.1 – Spraying Operations Using Coatings Containing Chromium, which regulated chrome spraying operations
- SCAQMD Rule 410 – Odors From Transfer Stations and Material Recovery Facilities, which addresses odors from transfer stations and material recovery facilities
- Intergovernmental Review comment letters for CEQA documents
- SCAQMD's land use guidance document
- Additional protection in toxics rules for sensitive receptors, such as more stringent requirements for chrome plating operations and diesel engines located near schools

2004 Addendum to the ATCP: An addendum to the ATCP was adopted by the SCAQMD Governing Board in 2004 (referred to herein as the 2004 Addendum to the ATCP) and served as a status report regarding implementation of the various mobile and stationary source strategies in the 2000 ATCP and introduced new measures to further address air toxics. The main elements of the 2004 Addendum to the ATCP were to address the progress made in implementation of the 2000 ATCP control strategies; provide a historical perspective of air toxic emissions and current air toxic levels; incorporate the Cumulative Impact Reduction Strategies approved by the SCAQMD Governing Board in 2003 and additional measures identified in the 2003 AQMP; project future air toxic levels to the extent feasible; and, summarize future efforts to develop the next ATCP. Significant progress had been made in implementing most of the SCAQMD strategies from the 2000 ATCP and the 2004 Addendum to the ATCP. CARB has also made notable progress in mobile source measures via its Diesel Risk Reduction Plan, especially for goods movement related sources, while the USEPA continued to implement their air toxic programs applicable to stationary sources

Clean Communities Plan: On November 5, 2010, the SCAQMD Governing Board approved the 2010 Clean Communities Plan (CCP). The CCP was an update to the 2000 Air Toxics Control Plan (ATCP) and the 2004 Addendum. The objective of the 2010 CCP is to reduce the exposure to air toxics and air-related nuisances throughout the district, with emphasis on cumulative impacts. The elements of the 2010 CCP are community exposure reduction, community participation, communication and outreach, agency coordination, monitoring and compliance, source-specific programs, and nuisance. The centerpiece of the 2010 CCP is a pilot study through which the SCAQMD staff will work with community stakeholders to identify and develop solutions community-specific to air quality issues in two communities: 1) the City of San Bernardino; and, 2) Boyle Heights and surrounding areas.

Control of TACs under the Air Toxics "Hot Spots" Act: In October 1992, the SCAQMD Governing Board adopted public notification procedures for Phase I and II facilities. These procedures specify that AB 2588 facilities must provide public notice when exceeding the following risk levels:

- Maximum Individual Cancer Risk (MICR): greater than 10 in one million (10×10^{-6})
- Total Hazard Index (HI): greater than 1.0 for TACs except lead, or > 0.5 for lead

Public notice is to be provided by letters mailed to all addresses and all parents of children attending school in the impacted area. In addition, facilities must hold a public meeting and provide copies of the facility risk assessment in all school libraries and a public library in the impacted area.

The AB2588 Toxics “Hot Spots” Program is implemented through SCAQMD Rule 1402 – Control of Toxic Air Contaminants from Existing Sources. The SCAQMD continues to review health risk assessments submitted. Notification is required from facilities with a significant risk under the AB 2588 program based on their initial approved health risk assessments and will continue on an ongoing basis as additional and subsequent health risk assessments are reviewed and approved.

There are currently about 400 core facilities in the SCAQMD’s AB2588 program. Since 1992 when the state Health and Safety Code incorporated a risk reduction requirement in the program, the SCAQMD has reviewed and approved over 300 HRAs, approximately 45 facilities were required to do a public notice, and 23 facilities were subject to risk reduction. Currently, over 96 percent of the facilities in the program have cancer risks below ten in a million and over 98 percent have acute and chronic hazard indices of less than one.

CEQA Intergovernmental Review Program: The SCAQMD staff, through its Intergovernmental Review (IGR) provides comments to lead agencies on air quality analyses and mitigation measures in CEQA documents. The following are some key programs and tools that have been developed more recently to strengthen air quality analyses, specifically as they relate to exposure of mobile source air toxics:

- SCAQMD's Mobile Source Committee approved the "Health Risk Assessment Guidance for Analyzing Cancer Risks from Mobile Source Diesel Emissions" (August 2002). This document provides guidance for analyzing cancer risks from diesel particulate matter from truck idling and movement (e.g., truck stops, warehouse and distribution centers, or transit centers), ship hotelling at ports, and train idling.

- CalEPA and CARB's "Air Quality and Land Use Handbook: A Community Health Perspective" (April 2005), provides recommended siting distances for incompatible land uses.

- Western Riverside Council of Governments Air Quality Task Force developed a policy document titled, "Good Neighbor Guidelines for Siting New and/or Modified Warehouse/Distribution Facilities" (September 2005). This document provides guidance to local government on preventive measures to reduce neighborhood exposure to TACs from warehousing facilities.

Environmental Justice: Environmental justice (EJ) has long been a focus of the SCAQMD. In 1990, the SCAQMD formed an Ethnic Community Advisory Group that has since been restructured as the Environmental Justice Advisory Group (EJAG). EJAG's mission is to advise and assist SCAQMD in protecting and improving public health in SCAQMD's most impacted communities through the reduction and prevention of air pollution.

In 1997, the SCAQMD Governing Board adopted four guiding principles and ten initiatives (http://www.aqmd.gov/ej/history.htm) to ensure environmental equity. Also in 1997, the SCAQMD Governing Board expanded the initiatives to include the "Children's Air Quality Agenda" focusing on the disproportionate impacts of poor air quality on children. Some key initiatives that have been implemented were the Multiple Air Toxics Exposure Studies (MATES, MATES II and MATES III); the Clean Fleet Rules, the Cumulative Impacts strategies; funding for lower emitting technologies under the Carl Moyer Program; the Guidance Document for Addressing Air Quality Issues in General Plans and Local Planning; a guidance document on Air Quality Issues in School Site Selection; and the 2000 ATCP and the 2004 Addendum to the ATCP. Key initiatives focusing on communities and residents include the Clean Air Congress; the Clean School Bus Program; Asthma and Air Quality Consortium; Brain and Lung Tumor and Air Pollution Foundation; air quality presentations to schools and community and civic groups; and Town Hall meetings. Technological and scientific projects and programs have been a large part of the SCAQMD's EJ program since its inception. Over time, the EJ program's focus on public education, outreach, and opportunities for public participation have greatly increased.

Public education materials and other resources for the public are available on the SCAQMD's website (www.aqmd.gov).

AB 2766 Subvention Funds: AB2766 subvention funds are monies collected by the state as part of vehicle registration and passed through to the SCAQMD for funding projects of local cities, among others, that reduce motor vehicle air pollutants. The Clean Fuels Program, funded by a surcharge on motor vehicle registrations in the SCAQMD, reduces TAC emissions through co-funding projects to develop and demonstrate low-emission clean fuels and advanced technologies, and to promote commercialization and deployment of promising or proven technologies in Southern California.

Carl Moyer Program: Another program that targets diesel emission reductions is the Carl Moyer Program which provides grants for projects that achieve early or extra emission reductions beyond what is required by regulations. Examples of eligible projects include cleaner on-road, off-road, marine, locomotive, and stationary agricultural pump engines. Other endeavors of the SCAQMD's Technology Advancement Office help to reduce diesel PM emissions through co-funding research and demonstration projects of clean technologies, such as low-emitting locomotives.

Control of TACs with Risk Reduction Audits and Plans: SB 1731, enacted in 1992 and codified at HSC §44390 et seq., amended AB 2588 to include a requirement for facilities with significant risks to prepare and implement a risk reduction plan which will reduce the risk below a defined significant risk level within specified time limits. SCAQMD Rule 1402 was adopted on April 8, 1994 to implement the requirements of SB 1731.

In addition to the TAC rules adopted by SCAQMD under authority of AB 1807 and SB 1731, the SCAQMD has adopted source-specific TAC rules, based on the specific level of TAC emitted and the needs of the area. These rules are similar to the state's ATCMs because they are source-specific and only address emissions and risk from specific compounds and operations.

Multiple Air Toxics Exposure Studies (MATES): In 1986, SCAQMD conducted the first MATES Study to determine the Basin-wide risks associated with major airborne carcinogens. At the time, the state of technology was such that only twenty known air toxic compounds could be analyzed and diesel exhaust particulate did not have an agency accepted carcinogenic health risk value. TACs are determined by the USEPA, and by the CalEPA, including the Office of Environmental Health Hazard Assessment and the ARB. For purposes of MATES, the California carcinogenic health risk factors were used. The maximum combined individual health risk for simultaneous exposure to pollutants under the study was estimated to be 600 to 5,000 in one million.

Multiple Air Toxics Exposure Study II (MATES II): At its October 10, 1997 meeting, the SCAQMD Governing Board directed staff to conduct a follow up to the MATES study to quantify the magnitude of population exposure risk from existing sources of selected air toxic contaminants at that time. The follow up study, MATES II, included a monitoring program of 40 known air toxic compounds, an updated emissions inventory of TACs (including microinventories around each of the 14 microscale sites), and a modeling effort to characterize health risks from hazardous air pollutants. The estimated basin-wide carcinogenic health risk from ambient measurements was 1,400 per million people. About 70 percent of the basin wide health risk was attributed to diesel particulate emissions; about 20 percent to other toxics associated with mobile sources (including benzene, butadiene, and formaldehyde); about 10 percent of basin wide health risk was attributed to stationary sources (which include industrial sources and other certain specifically identified commercial businesses such as dry cleaners and print shops.)

Multiple Air Toxics Exposure Study III (MATES III): MATES III was a follow up to previous air toxics studies in the Basin and was part of the SCAQMD Governing Board's 2003-04 Environmental Justice Workplan. The MATES III Study consists of several elements including a monitoring program, an updated emissions inventory of TACs, and a modeling effort to characterize carcinogenic health risk across the Basin. Besides toxics, additional measurements include organic carbon, elemental carbon, and total carbon, as well as, PM, including PM2.5. It did not estimate mortality or other health effects from particulate exposures. MATES III revealed a general downward trend in air toxic pollutant concentrations with an estimated basin-wide lifetime carcinogenic health risk of 1,200 in one million. Mobile sources accounted for 94 percent of the basin-wide lifetime carcinogenic health risk with diesel exhaust particulate contributing to 84 percent of the mobile source basin-wide lifetime carcinogenic health risk. Non-diesel carcinogenic health risk declined by 50 percent from the MATES II values.

Multiple Air Toxics Exposure Study IV (MATES IV): The MATES IV Study consisted of several elements including a monitoring program, an updated emissions inventory of toxic air contaminants, and a modeling effort to characterize risk across the Basin. The study focuses on the carcinogenic risk from exposure to air toxics. The population weighted risk of 367 per million was about 57% lower compared to the MATES III period (2005). The Final MATES IV also reported risks using new guidance for calculating health risks from the state Office of Environmental Health Hazard Assessment that take into account children’s greater risk from being exposed to cancer causing compounds. Even after accounting for the reduced level of exposure from the MATES IV study compared to MATES III, after applying the revised OEHHA methodology to the modeled air toxics levels, the MATES IV estimated population weighted risk is 897 per million, an increase of about 2.5 times higher.

Carcinogenic Health Risks from Toxic Air Contaminants: One of the primary health risks of concern due to exposure to TACs is the risk of contracting cancer. The carcinogenic potential of TACs is a particular public health concern because it is currently believed by many scientists that there is no "safe" level of exposure to carcinogens. Any exposure to a carcinogen poses some risk of causing cancer. It is currently estimated that about one in four deaths in the U.S. is attributable to cancer. About two percent of cancer deaths in the U.S. may be attributable to environmental pollution (Doll and Peto 1981). The proportion of cancer deaths attributable to air pollution has not been estimated using epidemiological methods.

Non-Cancer Health Risks from Toxic Air Contaminants: Unlike carcinogens, for most TAC non-carcinogens it is believed that there is a threshold level of exposure to the compound below which it will not pose a health risk. CalEPA's Office of Environmental Health Hazard Assessment (OEHHA) develops Reference Exposure Levels (RELs) for TACs which are health-conservative estimates of the levels of exposure at or below which health effects are not expected. The non-cancer health risk due to exposure to a TAC is assessed by comparing the estimated level of exposure to the REL. The comparison is expressed as the ratio of the estimated exposure level to the REL, called the hazard index (HI).

Climate Change

Global climate change is a change in the average weather of the earth, which can be measured by wind patterns, storms, precipitation, and temperature. Historical records have shown that temperature changes have occurred in the past, such as during previous ice ages. Data indicate that the current temperature record differs from previous climate changes in rate and magnitude. Gases that trap heat in the atmosphere are often called greenhouse gases (GHGs), comparable to a greenhouse, which captures and traps radiant energy. GHGs are emitted by natural processes and human activities. The accumulation of greenhouse gases in the atmosphere regulates the earth's temperature. Global warming is the observed increase in average temperature of the earth's surface and atmosphere. The primary cause of global warming is an increase of GHGs in the atmosphere. The six major GHGs are carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs), and perfluorocarbon (PFCs). The GHGs absorb longwave radiant energy emitted by the Earth, which warms the atmosphere. The GHGs also emit longwave radiation both upward to space and back down toward the surface of the Earth. The downward part of this longwave radiation emitted by the atmosphere is known as the "greenhouse effect." Emissions from human activities such as fossil fuel combustion for electricity production and vehicles have elevated the concentration of these gases in the atmosphere.

CO2 is an odorless, colorless greenhouse gas. Natural sources include the following: decomposition of dead organic matter; respiration of bacteria, plants, animals, and fungus; evaporation from oceans; and volcanic outgassing. Anthropogenic (human caused) sources of CO2 include burning coal, oil, gasoline, natural gas, and wood. CH4 is a flammable gas and is the main component of natural gas. N2O, also known as laughing gas, is a colorless greenhouse gas. Some industrial processes such as fossil fuel-fired power plants, nylon production, nitric acid production, and vehicle emissions also contribute to the atmospheric load of N2O. HFCs are synthetic man-made chemicals that are used as a substitute for chlorofluorocarbons (whose production was stopped as required by the Montreal Protocol) for automobile air conditioners and refrigerants. The two main sources of PFCs are primary aluminum production and semiconductor manufacture. SF6 is an inorganic, odorless, colorless, nontoxic, nonflammable gas. SF6 is used for insulation in electric power transmission and distribution equipment, in the magnesium industry, in semiconductor manufacturing, and as a tracer gas for leak detection.

Scientific consensus, as reflected in recent reports issued by the United Nations Intergovernmental Panel on Climate Change, is that the majority of the observed warming over the last 50 years can be attributable to increased concentration of GHGs in the atmosphere due to human activities. Industrial activities, particularly increased consumption of fossil fuels (e.g., gasoline, diesel, wood, coal, etc.), have heavily contributed to the increase in atmospheric levels of GHGs. The United Nations Intergovernmental Panel on Climate Change constructed several emission trajectories of

greenhouse gases needed to stabilize global temperatures and climate change impacts. It concluded that a stabilization of greenhouse gases at 400 to 450 ppm carbon dioxide-equivalent concentration is required to keep global mean warming below two degrees Celsius, which has been identified as necessary to avoid dangerous impacts from climate change.
The potential health effects from global climate change may arise from temperature increases, climate-sensitive diseases, extreme events, air quality impacts, and sea level rise. There may be direct temperature effects through increases in average temperature leading to more extreme heat waves and less extreme cold spells. Those living in warmer climates are likely to experience more stress and heat-related problems (e.g., heat rash and heat stroke). In addition, climate sensitive diseases may increase, such as those spread by mosquitoes and other disease carrying insects. Those diseases include malaria, dengue fever, yellow fever, and encephalitis. Extreme events such as flooding, hurricanes, and wildfires can displace people and agriculture, which would have negative consequences. Drought in some areas may increase, which would decrease water and food availability. Global warming may also contribute to air quality problems from increased frequency of smog and particulate air pollution.

The impacts of climate change will also affect projects in various ways. Effects of climate change are rising sea levels and changes in snow pack. The extent of climate change impacts at specific locations remains unclear. It is expected that Federal, State and local agencies will more precisely quantify impacts in various regions. As an example, it is expected that the California Department of Water Resources will formalize a list of foreseeable water quality issues associated with various degrees of climate change. Once state government agencies make these lists available, they could be used to more precisely determine to what extent a project creates global climate change impacts.

<u>Federal</u>

Greenhouse Gas Endangerment Findings: On December 7, 2009, the USEPA Administrator signed two distinct findings regarding greenhouse gases pursuant to CAA §202 (a). The Endangerment Finding stated that CO2, CH4, N2O, HFCs, PFCs, and SF6 taken in combination endanger both the public health and the public welfare of current and future generations. The *Cause or Contribute Finding* stated that the combined emissions from motor vehicles and motor vehicle engines contribute to the greenhouse gas air pollution that endangers public health and welfare. These findings were a prerequisite for implementing GHG standards for vehicles. The USEPA and the National Highway Traffic Safety Administration (NHTSA) finalized emission standards for light-duty vehicles in May 2010 and for heavy-duty vehicles in August of 2011.

Renewable Fuel Standard: The Renewable Fuel Standard (RFS) program was established under the Energy Policy Act (EPAct) of 2005, and required 7.5 billion gallons of renewable-fuel to be blended into gasoline by 2012. Under the Energy Independence and Security Act (EISA) of 2007, the RFS program was expanded to include diesel, required the volume of renewable fuel blended into transportation fuel be increased from nine billion gallons in 2008 to 36 billion gallons by 2022, established new categories of renewable fuel and required USEPA to apply lifecycle GHG performance threshold standards so that each category of renewable fuel emits fewer greenhouse gases than the petroleum fuel it replaces. The RFS is expected to reduce greenhouse gas emissions by 138 million metric tons[6], about the annual emissions of 27 million passenger vehicles, replacing about seven percent of expected annual diesel consumption and decreasing oil imports by $41.5 billion.

GHG Tailoring Rule: On May 13, 2010, USEPA finalized the GHG Tailoring Rule to phase in the applicability of the Prevention of Significant Deterioration (PSD) and Title V operating permit programs for GHGs. The GHG Tailoring Rule was tailored to include the largest GHG emitters, while excluding smaller sources (restaurants, commercial facilities and small farms). The first phase (from January 2, 2011 to June 30, 2011) addressed the largest sources that contributed 65 percent of the stationary GHG sources. Title V GHG requirements were triggered only when affected facility owners/operators were applying, renewing or revising their permits for non-GHG pollutants. PSD GHG requirements were applicable only if sources were undergoing permitting actions for other non-GHG pollutants and the permitted action would increase GHG emission by 75,000 metric tons of CO2 equivalent emissions (CO2e) per year or more.

The second phase (from July 1, 2011 to June 30, 2013) included sources that emit or have the potential to emit 100,000 of CO2e metric tons per year or more. Newly constructed sources that are not major sources for non-GHG pollutants would not be subject to PSD GHG requirements unless it emits 100,000 metric tons of CO2e per year or more. Modifications to a major source would not be subject to PSD GHG requirements unless it generates a net increase of 75,000 metric tons of CO2e per year or more. Sources not subject to Title V would not be subject to Title V GHG requirements unless 100,000 metric tons of CO2e per year or more would be emitted.

The third phase of the GHG Tailoring Rule, finalized on July 12, 2012, determined not to lower the current PSD and Title V applicability thresholds for GHG-emitting sources established in the GHG Tailoring Rule for phases 1 and 2. The GHG Tailoring Rule also promulgated regulatory revisions for better implementation of the federal program for establishing plantwide applicability limitations (PALs) for GHG emissions, which will improve the administration of the GHG PSD permitting programs.

GHG Reporting Program: USEPA issued the Mandatory Reporting of Greenhouse Gases Rule (40 CFR Part 98) under the 2008 Consolidated Appropriations Act. The Mandatory Reporting of Greenhouse Gases Rule requires reporting of GHG data from large sources and suppliers under the Greenhouse Gas Reporting Program (GHGRP). Suppliers of certain products that would result in GHG emissions if released, combusted or oxidized; direct emitting source categories; and facilities that inject CO2 underground for geologic sequestration or any purpose other than geologic sequestration are included. Facilities that emit 25,000 metric tons or more per year of GHGs as CO2e are required to submit annual reports to USEPA. For the 2010 calendar, there were 6,260 entities that reported GHG data under this program, and 467 of the entities were from California. Of the 3,200 million metric tons of CO2e that were reported nationally, 112 million metric tons of CO2e were from California. Power plants were the largest stationary source of direct U.S. GHG emissions with 2,326 million metric tons of CO2e, followed by refineries with 183 million metric tons of CO2e. CO2 emissions accounted for largest share of direct emissions with

[6] One metric ton is equal to 2, 205 pounds.

95 percent, followed by CH4 with four percent, and N2O and fluorinated gases representing the remaining one percent.

State

Executive Order S-3-05: In June 2005, Governor Schwarzenegger signed Executive Order S-3-05, which established emission reduction targets. The goals would reduce GHG emissions to 2000 levels by 2010, then to 1990 levels by 2020, and to 80 percent below 1990 levels by 2050.

AB 32 - Global Warming Solutions Act: On September 27, 2006, AB 32, the California Global Warming Solutions Act of 2006, was signed by Governor Schwarzenegger. AB 32 expanded on Executive Order S-3-05. The California legislature stated that "global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California." AB 32 represents the first enforceable state-wide program in the U.S. to cap all GHG emissions from major industries that includes penalties for non-compliance. While acknowledging that national and international actions will be necessary to fully address the issue of global warming, AB 32 lays out a program to inventory and reduce greenhouse gas emissions in California and from power generation facilities located outside the state that serve California residents and businesses. AB 32 requires CARB to:

- Establish a statewide GHG emissions cap for 2020, based on 1990 emissions by January 1, 2008;
- Adopt mandatory reporting rules for significant sources of GHG by January 1, 2008;
- Adopt a GHG emissions reduction plan by January 1, 2009, indicating how the GHG emissions reductions will be achieved via regulations, market mechanisms, and other actions; and
- Adopt regulations to achieve the maximum technologically feasible and cost-effective reductions of GHG by January 1, 2011.

The combination of Executive Order S-3-05 and AB 32 will require significant development and implementation of energy efficient technologies and shifting of energy production to renewable sources.

Consistent with the requirement to develop an emission reduction plan, CARB prepared a Scoping Plan indicating how GHG emission reductions will be achieved through regulations, market mechanisms, and other actions. The Scoping Plan was released for public review and comment in October 2008 and approved by CARB on December 11, 2008. The Scoping Plan calls for reducing GHG emissions to 1990 levels by 2020. This means cutting approximately 30 percent from business-as-usual (BAU) emission levels projected for 2020, or about 15 percent from today's levels. Key elements of CARB staff's recommendations for reducing California's GHG emissions to 1990 levels by 2020 contained in the Scoping Plan include the following:

- Expansion and strengthening of existing energy efficiency programs and building and appliance standards;
- Expansion of the Renewables Portfolio Standard to 33 percent;
- Development of a California cap-and-trade program that links with other Western Climate Initiative (WCI) partner programs to create a regional market system;
- Establishing targets for transportation-related greenhouse gases and pursuing policies and incentives to achieve those targets;
- Adoption and implementation of existing state laws and policies, including California's clean car standards, goods movement measures, and the Low Carbon Fuel Standard (LCFS); and
- Targeted fees, including a public good charge on water use, fees on high global warming potential (GWP) gases and a fee to fund the state's long-term commitment to AB 32 administration.

In response to the comments received on the Draft Scoping Plan and at the November 2008 public hearing, CARB made a few changes to the Draft Scoping Plan, primarily to:

- State that California "will transition to 100 percent auction" of allowances and expects to "auction significantly more [allowances] than the Western Climate Initiative minimum;"
- Make clear that allowance set-asides could be used to provide incentives for voluntary renewable power purchases by businesses and individuals and for increased energy efficiency;
- Make clear that allowance set-asides can be used to ensure that voluntary actions, such as renewable power purchases, can be used to reduce greenhouse gas emissions under the cap;
- Provide allowances are not required from carbon neutral projects; and
- Mandate that commercial recycling be implemented to replace virgin raw materials with recyclables.

SB 97 – CEQA, Greenhouse Gas Emissions: On August 24, 2007, Governor Schwarzenegger signed into law SB 97 – CEQA: Greenhouse Gas Emissions, and stated, "This bill advances a coordinated policy for reducing greenhouse gas emissions by directing the Office of Planning and Research (OPR) and the Resources Agency to develop CEQA guidelines on how state and local agencies should analyze, and when necessary, mitigate greenhouse gas emissions." As directed by SB 97, the Natural Resources Agency adopted amendments to the CEQA Guidelines for GHG emissions on December 30, 2009 to provide guidance to public agencies regarding the analysis and mitigation of the effects of GHG emissions in draft CEQA documents. The amendments did not establish a threshold for significance for GHG emissions. The amendments became effective on March 18, 2010.

***OPR - Technical Advisory on CEQA and Climate Change*:** Consistent with SB 97, on June 19, 2008, OPR released its "Technical Advisory on CEQA and Climate Change," which was developed in cooperation with the Resources Agency, the CalEPA, and the CARB. According to OPR, the "Technical Advisory" offers the informal interim guidance regarding the steps lead agencies should take to address climate change in their CEQA documents, until CEQA guidelines are developed pursuant to SB 97 on how state and local agencies should analyze, and when necessary, mitigate greenhouse gas emissions.

According to OPR, lead agencies should determine whether greenhouse gases may be generated by a proposed project, and if so, quantify or estimate the GHG emissions by type and source. Second, the lead agency must assess whether those emissions are individually or cumulatively significant. When assessing whether a project's effects on climate change are "cumulatively considerable" even though its GHG contribution may be individually limited, the lead agency must consider the impact of the project when viewed in connection with the effects of past, current, and probable future projects. Finally, if the lead agency determines that the GHG emissions from the project as proposed are potentially significant, it must investigate and implement ways to avoid, reduce, or otherwise mitigate the impacts of those emissions.

In 2009, total California greenhouse gas emissions were 457 million metric tons of CO2e (MMTCO2e); net emissions were 453 MMTCO2e, reflecting the influence of sinks (net CO2 flux from forestry). While total emissions have increased by 5.5 percent from 1990 to 2009, emissions decreased by 5.8 percent from 2008 to 2009 (485 to 457 MMTCO2e). The total net emissions between 2000 and 2009 decreased from 459 to 453 MMTCO2e, representing a 1.3 percent decrease from 2000 and a 6.1 percent increase from the 1990 emissions level. The transportation sector accounted for approximately 38 percent of the total emissions, while the industrial sector accounted for approximately 20 percent. Emissions from electricity generation were about 23 percent with almost equal contributions from in-state and imported electricity.

Per capita emissions in California have slightly declined from 2000 to 2009 (by 9.7 percent), but the overall nine percent increase in population during the same period offsets the emission reductions. From a per capita sector perspective, industrial per capita emissions have declined 21 percent from 2000 to 2009, while per capita emissions for ozone depleting substance (ODS) substitutes saw the highest increase (52 percent).

From a broader geographical perspective, the state of California ranked second in the U.S. for 2007 greenhouse gas emissions, only behind Texas. However, from a per capita standpoint, California had the 46th lowest GHG emissions. On a global scale, California had the 14th largest carbon dioxide emissions and the 19th largest per capita emissions. The GHG inventory is divided into three categories: stationary sources, on-road mobile sources, and off-road mobile sources.

AB 1493 Vehicular Emissions - CO2: Prior to the USEPA and NHTSA joint rulemaking, Governor Schwarzenegger signed Assembly Bill AB 1493 (2002). AB 1493 requires that CARB develop and adopt, by January 1, 2005, regulations that achieve "the maximum feasible reduction of greenhouse gases emitted by passenger vehicles and light-duty trucks and other vehicles determined by CARB to be vehicles whose primary use is noncommercial personal transportation in the state."

CARB originally approved regulations to reduce GHGs from passenger vehicles in September 2004, with the regulations to take effect in 2009 (see amendments to CCR Title 13 §§1900 and 1961 (13 CCR 1900, 1961), and the adoption of CCR Title 13 §1961.1 (13 CCR 1961.1)). California's first request to the USEPA to implement GHG standards for passenger vehicles was made in December 2005 and subsequently denied by the USEPA in March 2008. The USEPA then granted California the authority to implement GHG emission reduction standards for new passenger cars, pickup trucks and sport utility vehicles on June 30, 2009.

On April 1, 2010, CARB filed amended regulations for passenger vehicles as part of California's commitment toward the national program to reduce new passenger vehicle GHGs from 2012 through 2016. The amendments will prepare California to harmonize its rules with the federal Light-Duty Vehicle GHG Standards and CAFE Standards.

SB 1368: SB 1368 is the companion bill of AB 32 and was signed by Governor Schwarzenegger in September 2006. SB 1368 required the CPUC to establish a GHG emission performance standard for baseload generation from investor owned utilities by February 1, 2007. The CEC was also required to establish a similar standard for local publicly owned utilities by June 30, 2007. These standards cannot exceed the greenhouse gas emission rate from a baseload combined-cycle natural gas fired plant. The legislation further required that all electricity provided to California, including imported electricity, must be generated from plants that meet the standards set by the PUC and CEC.

Executive Order S-1-07: Governor Schwarzenegger signed Executive Order S-1-07 in 2007 which established the transportation sector as the main source of GHG emissions in California. Executive Order S-1-07 proclaims that the transportation sector accounts for over 40 percent of statewide GHG emissions. Executive Order S-1-07 also establishes a goal to reduce the carbon intensity of transportation fuels sold in California by a minimum of 10 percent by 2020.

In particular, Executive Order S-1-07 established the LCFS and directed the Secretary for Environmental Protection to coordinate the actions of the CEC, CARB, the University of California, and other agencies to develop and propose protocols for measuring the "life-cycle carbon intensity" of transportation fuels. The analysis supporting development of the protocols was included in the SIP for alternative fuels (State Alternative Fuels Plan adopted by CEC on December 24, 2007) and was submitted to CARB for consideration as an "early action" item under AB 32. CARB adopted the LCFS on April 23, 2009.

SB 375: SB 375, signed into law in September 2008, aligns regional transportation planning efforts, regional GHG reduction targets, and land use and housing allocation. As part of the alignment, SB 375 requires Metropolitan Planning Organizations (MPOs) to adopt a Sustainable Communities Strategy (SCS) or Alternative Planning Strategy (APS) which prescribes land use allocation in that MPO's Regional Transportation Plan (RTP). CARB, in consultation with MPOs, is required to provide each affected region with reduction targets for GHGs emitted by passenger cars and light trucks in the region for the years 2020 and 2035. These reduction targets will be updated every eight years but can be updated every four years if advancements in emissions technologies affect the reduction strategies to achieve the targets. CARB is also charged with reviewing each MPO's SCS or APS for consistency with its assigned GHG emission reduction targets. If MPOs do not meet the GHG reduction targets, transportation projects located in the MPO boundaries would not be eligible for funding programmed after January 1, 2012.

CARB appointed the Regional Targets Advisory Committee (RTAC), as required under SB 375, on January 23, 2009. The RTAC's charge was to advise CARB on the factors to be considered and methodologies to be used for establishing regional targets. The RTAC provided its recommendation to CARB on September 29, 2009. CARB was required to adopt final targets by September 30, 2010.

Executive Order S-13-08: Governor Schwarzenegger signed Executive Order S-13-08 on November 14, 2008 which directed California to develop methods for adapting to climate change through preparation of a statewide plan. Executive Order S-13-08 directed OPR, in cooperation with the Resources Agency, to provide land use planning guidance related to sea level rise and other climate change impacts by May 30, 2009. Executive Order S-13-08 also directed the Resources Agency to develop a state Climate Adaptation Strategy by June 30, 2009 and to convene an independent panel to complete the first California Sea Level Rise Assessment Report. The assessment report was required to be completed by December 1, 2010 and required to meet the following four criteria:

1. Project the relative sea level rise specific to California by taking into account issues such as coastal erosion rates, tidal impacts, El Niño and La Niña events, storm surge, and land subsidence rates;
2. Identify the range of uncertainty in selected sea level rise projections;
3. Synthesize existing information on projected sea level rise impacts to state infrastructure (e.g., roads, public facilities, beaches), natural areas, and coastal and marine ecosystems; and
4. Discuss future research needs relating to sea level rise in California.

SB 1078, SB 107 and Executive Order S-14-08: SB 1078 (Chapter 516, Statutes of 2002) requires retail sellers of electricity, including investor owned utilities and community choice aggregators, to provide at least 20 percent of their supply from renewable sources by 2017. SB 107 (Chapter 464, Statutes of 2006) changed the target date to 2010. In November 2008, Governor Schwarzenegger signed Executive Order S-14-08, which expands the state's Renewable Portfolio Standard to 33 percent renewable power by 2020.

SB X-1-2: SB X1-2 was signed by Governor Brown in April 2011. SB X1-2 created a new Renewables Portfolio Standard (RPS), which pre-empted CARB's 33 percent Renewable Electricity Standard. The new RPS applies to all electricity retailers in the state including publicly owned utilities (POUs), investor-owned utilities, electricity service providers, and community choice aggregators. These entities must adopt the new RPS goals of 20 percent of retails sales from renewables by the end of 2013, 25 percent by the end of 2016, and the 33 percent requirement by the end of 2020.

Executive Order B-30-15: Governor Brown signed Executive Order B-30-15 in April 2015 to establish a California greenhouse gas reduction target of 40 percent below 1990 levels by 2030. This is the most aggressive benchmark enacted by any government in North America to reduce carbon emissions over the next decade and a half. California is on track to meet or exceed the current target of reducing greenhouse gas emissions to 1990 levels by 2020, as established by AB32. California's new emission reduction target of 40 percent below 1990 levels by 2030 will make it possible to reach the ultimate goal of reducing emissions 80 percent under 1990 levels by 2050.

<u>SCAQMD</u>

The SCAQMD adopted a "Policy on Global Warming and Stratospheric Ozone Depletion" on April 6, 1990. The policy commits the SCAQMD to consider global impacts in rulemaking and in drafting revisions to the AQMP. In March 1992, the SCAQMD Governing Board reaffirmed this policy and adopted amendments to the policy to include support of the adoption of a California GHG emission reduction goal.

Basin GHG Policy and Inventory: The SCAQMD has established a policy, adopted by the SCAQMD Governing Board at its September 5, 2008 meeting, to actively seek opportunities to reduce emissions of criteria, toxic, and climate change pollutants. The policy includes the intent to assist businesses and local governments implementing climate change measures, decrease the agency's carbon footprint, and provide climate change information to the public. The SCAQMD will take the following actions:

1. Work cooperatively with other agencies/entities to develop quantification protocols, rules, and programs related to greenhouse gases;
2. Share experiences and lessons learned relative to SCAQMD Regulation XX - Regional Clean Air Incentives Market (RECLAIM), to help inform state, multi-state, and federal development of effective, enforceable cap-and-trade programs. To the extent practicable, staff will actively engage in current and future regulatory development to ensure that early actions taken by local businesses to reduce greenhouse gases will be treated fairly and equitably. SCAQMD staff will seek to streamline administrative procedures to the extent feasible to facilitate the implementation of AB 32 measures;
3. Review and comment on proposed legislation related to climate change and greenhouse gases, pursuant to the 'Guiding Principles for SCAQMD Staff Comments on Legislation Relating to Climate Change' approved at the SCAQMD Governing Board's Special Meeting in April 2008;
4. Provide higher priority to funding Technology Advancement Office (TAO) projects or contracts that also reduce greenhouse gas emissions;
5. Develop recommendations through a public process for an interim greenhouse gas CEQA significance threshold, until such time that an applicable and appropriate statewide greenhouse gas significance level is established. Provide guidance on

analyzing greenhouse gas emissions and identify mitigation measures. Continue to consider GHG impacts and mitigation in SCAQMD lead agency documents and in comments when SCAQMD is a responsible agency;

6. Revise the SCAQMD's Guidance Document for Addressing Air Quality Issues in General Plans and Local Planning to include information on greenhouse gas strategies as a resource for local governments. The Guidance Document will be consistent with state guidance, including CARB's Scoping Plan;
7. Update the Basin's greenhouse gas inventory in conjunction with each Air Quality Management Plan. Information and data used will be determined in consultation with CARB, to ensure consistency with state programs. Staff will also assist local governments in developing greenhouse gas inventories;
8. Bring recommendations to the SCAQMD Governing Board on how the agency can reduce its own carbon footprint, including drafting a Green Building Policy with recommendations regarding SCAQMD purchases, building maintenance, and other areas of products and services. Assess employee travel as well as other activities that are not part of a GHG inventory and determine what greenhouse gas emissions these activities represent, how they could be reduced, and what it would cost to offset the emissions;
9. Provide educational materials concerning climate change and available actions to reduce greenhouse gas emissions on the SCAQMD website, in brochures, and other venues to help cities and counties, businesses, households, schools, and others learn about ways to reduce their electricity and water use through conservation or other efforts, improve energy efficiency, reduce vehicle miles traveled, access alternative mobility resources, utilize low emission vehicles and implement other climate friendly strategies; and
10. Conduct conferences, or include topics in other conferences, as appropriate, related to various aspects of climate change, including understanding impacts, technology advancement, public education, and other emerging aspects of climate change science.

On December 5, 2008, the SCAQMD Governing Board adopted the staff proposal for an interim GHG significance threshold for projects where the SCAQMD is lead agency. SCAQMD's recommended interim GHG significance threshold proposal uses a tiered approach to determining significance. Tier 1 consists of evaluating whether or not the project qualifies for any applicable exemption under CEQA. Tier 2 consists of determining whether or not the project is consistent with a GHG reduction plan that may be part of a local general plan, for example. Tier 3 establishes a screening significance threshold level to determine significance using a 90 percent emission capture rate approach, which corresponds to 10,000 metric tons of CO2 equivalent emissions per year (MTCO2e/year). Tier 4, to be based on performance standards, is yet to be developed. Under Tier 5 the project proponent would allow offsets to reduce GHG emission impacts to less than the proposed screening level. If CARB adopts statewide significance thresholds, SCAQMD staff plans to report back to the SCAQMD Governing Board regarding any recommended changes or additions to the SCAQMD's interim threshold.

Table 3-3 presents the GHG emission inventory by major source categories in calendar year 2008, as identified in the 2012 AQMP for the South Coast Air Basin. The emissions reported herein are based on in-basin energy consumption and do not include out-of-basin energy production (e.g., power plants, crude oil production) or delivery emissions (e.g., natural gas pipeline loss). Three major GHG pollutants have been included: CO2, N2O, and CH4. These GHG emissions are reported in MMTCO2e. Mobile sources generate 59.4 percent of the emissions, and include airport equipment, and oil and gas drilling equipment. The remaining 40.6 percent of the total Basin GHG emissions are from stationary and area sources. The largest stationary/area source is fuel combustion, which is 27.8 percent of the total Basin GHG emissions (68.6 percent of the GHG emissions from the stationary and area source category).

Air Quality – Ozone Depletion

The Montreal Protocol on Substances that Deplete the Ozone Layer (Montreal Protocol) is an international treaty designed to phase out halogenated hydrocarbons such as chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs), which are considered ODSs. The Montreal Protocol was first signed in September 16, 1987 and has been revised seven times. The U.S. ratified the original Montreal Protocol and each of its revisions.

<u>Federal</u>

Under the CAA Title VI, the USEPA is assigned responsibility for implementing programs that protect the stratospheric ozone layer. 40 CFR Part 82 contains USEPA's regulations specific to protecting the ozone layer. These USEPA regulations phase out the production and import of ozone depleting substances (ODSs) consistent with the Montreal Protocol. ODSs are typically used as refrigerants or as foam blowing agents. ODS are regulated as Class I or Class II controlled substances. Class I substances have a higher ozone-depleting potential and have been completely phased out in the U.S., except for exemptions allowed under the Montreal Protocol. Class II substances are HCFCs, which are transitional substitutes for many Class I substances and are being phased out.

Table 3-3
2008 GHG Emissions for the South Coast Air Basin

		Emission (TPD)			Emission (TPY)			MMTONS
CODE	**Source Category**	**CO2**	**N2 O**	**CH4**	**CO2**	**N2O**	**CH4**	**CO2 e**
	Fuel Combustion							
10	Electric Utilities	34,303	.08	0.71	12,520,562	29.0	258	11.4
20	Cogeneration	872	.00	0.02	318,340	0.60	6.00	0.29
30	Oil and Gas Production (combustion)	2,908	.01	0.08	1,061,470	4.71	29.5	0.96
40	Petroleum Refining (Combustion)	44,654	.06	0.57	16,298,766	20.7	207	14.8
50	Manufacturing and Industrial	22,182	.06	0.48	8,096,396	20.9	174	7.35
52	Food and Agricultural Processing	927	00	0.02	338,516	0.84	7.16	0.31
60	Service and Commercial	21,889	0.08	0.59	7,989,416	30.8	215	7.26
99	Other (Fuel Combustion)	2,241	0.2	0.16	818,057	8.58	58	0.75
Total Fuel Combustion		**129,977**	**0.32**	**2.62**	**47,441,523**	**116**	**956**	**43.1**
	Waste Disposal							
110	Sewage Treatment	26.4	0.00	0.00	9,653	0.12	1.50	0.01
120	Landfills	3,166	0.04	505	1,155,509	14.0	184,451	4.57
130	Incineration	580	0.00	0.02	211,708	0.81	5.48	0.19
199	Other (Waste Disposal)			2.25	0	0.00	820	0.02
Total Waste Disposal		**3,772**	**0.04**	**508**	**1,376,870**	**14.9**	**185,278**	**4.78**
	Cleaning and Surface Coatings							
210	Laundering							
220	Degreasing							
230	Coatings and Related Processes	27.1	0.00	0.21	9,890	0.02	78.0	0.01
240	Printing			0.00	0	0.00	0.00	0.00
250	Adhesives and Sealants			0.00	0	0.00	0.00	0.00
299	Other (Cleaning and Surface Coatings)	2,621	0.00	0.12	956,739	1.20	43.9	0.87
Total Cleaning and Surface Coatings		**2,648**	**0.00**	**0.33**	**966,628**	**1.22**	**122**	**0.88**
	Petroleum Production and Marketing							
310	Oil and Gas Production	92.1	0.00	0.92	33,605	0.06	336	0.04
320	Petroleum Refining	770	0.00	1.65	280,932	0.36	603	0.27
330	Petroleum Marketing			83.8	0	0.00	30,598	0.58
399	Other (Petroleum Production and Marketing)			0.00	0	0.00	0	0.00
Total Petroleum Production and Marketing		**862**	**0.00**	**86.4**	**314,536**	**0.42**	**31,537**	**0.89**

Table 3-3 (Continued)

2008 GHG Emissions for the South Coast Air Basin

		Emission (TPD)			Emission (TPY)			MMTONS
CODE	**Source Category**	**CO2**	**N2 O**	**CH4**	**CO2**	**N2O**	**CH4**	**CO2e**
	Industrial Processes							
410	Chemical			0.92	0	0.00	337	0.01
420	Food and Agriculture			0.02	0	0.00	7.10	0.00
430	Mineral Processes	279	0.00	0.05	101,804	0.19	17.3	0.09
440	Metal Processes			0.02	0	0.00	9.10	0.00
450	Wood and Paper			0.00	0	0.00	0.00	0.00
460	Glass and Related Products			0.00	0	0.00	0.90	0.00
470	Electronics			0.00	0	0.00	0.00	0.00
499	Other (Industrial Processes)	0.08	0.00	0.47	28	0.00	172	0.00
	Total Industrial Processes	**279**	**0.00**	**1.49**	**101,832**	**0.19**	**543**	**0.10**
	Solvent Evaporation							
510	Consumer Products			0.00	0.00	0.00	0.00	0.00
520	Architectural Coatings and Related Solvent			0.00	0.00	0.00	0.00	0.00
530	Pesticides/Fertilizers			0.00	0.00	0.00	0.00	0.00
540	Asphalt Paving/Roofing			0.07	0.00	0.00	24.20	0.00
	Total Solvent Evaporation	**0.00**	**0.00**	**0.07**	**0.00**	**0.00**	**24.20**	**0.00**
	Miscellaneous Processes							
610	Residential Fuel Combustion	38,850	0.12	0.95	14,180,326	45.3	347	12.9
620	Farming Operations			25.6	0.00	0.00	9,354	0.18
630	Construction and Demolition			0.00	0.00	0.00	0	0.00
640	Paved Road Dust			0.00	0.00	0.00	0	0.00
645	Unpaved Road Dust			0.00	0.00	0.00	0	0.00
650	Fugitive Windblown Dust			0.00	0.00	0.00	0	0.00
660	Fires			0.08	0.00	0.00	30.9	0.00
670	Waste Burning and Disposal			0.58	0.00	0.00	212	0.00
680	Utility Equipment				0.00	0.00		0.00
690	Cooking			0.64	0.00	0.00	235	0.00
699	Other (Miscellaneous Processes			0.00	0.00	0.00	0	0.00
	Total Miscellaneous Processes	**38,850**	**0.12**	**27.9**	**14,180,326**	**45.3**	**10,17 9**	**13.1**

Table 3-3 (Concluded)
2008 GHG Emissions for the South Coast Air Basin

		Emission (TPD)			Emission (TPY)			MMTONS
CODE	**Source Category**	**CO2**	**N2O**	**CH4**	**CO2**	**N2O**	**CH4**	**CO2e**
	On-Road Motor Vehicles							
710	Light Duty Passenger Auto (LDA)	84,679	2.72	3.62	30,907,957	993	1,321	28.3
722	Light Duty Trucks 1 (T1 : up to 3750 lb.)	22,319	0.72	0.96	8,146,321	263	350	7.47
723	Light Duty Trucks 2 (T2 : 3751-5750 lb.)	33,495	1.08	1.43	12,225,619	392	523	11.2
724	Medium Duty Trucks (T3 : 5751-8500 lb.)	29,415	0.94	1.25	10,736,309	343	456	9.85
732	Light Heavy Duty Gas Trucks 1 (T4 : 8501-10000 lb.)	8,195	0.16	0.21	2,991,059	57.3	76.7	2.73
733	Light Heavy Duty Gas Trucks 2 (T5 : 10001-14000 lb.)	1,116	0.05	0.07	407,174	19.0	25.6	0.38
734	Medium Heavy Duty Gas Trucks (T6 : 14001-33000 lb.)	727	0.02	0.20	265,506	5.48	73.0	0.24
736	Heavy Heavy Duty Gas Trucks ((HHDGT > 33000 lb.)	102	0.01	0.01	37,198	2.19	2.56	0.03
742	Light Heavy Duty Diesel Trucks 1 (T4 : 8501-10000 lb.)	2,166	0.02	0.02	790,600	6.94	7.30	0.72
743	Light Heavy Duty Diesel Trucks 2 (T5 : 10001-14000 lb.)	735	0.01	0.01	268,413	2.56	2.92	0.24
744	Medium Heavy Duty Diesel Truck (T6 : 14001-33000 lb.)	5,422	0.02	0.02	1,978,974	8.40	8.76	1.80
746	Heavy Heavy Duty Diesel Trucks (HHDDT > 33000 lb.)	17,017	0.05	0.05	6,211,247	17.5	16.4	5.64
750	Motorcycles (MCY)	7,959	0.26	0.34	2,904,910	94.9	124	2.66
760	Diesel Urban Buses (UB)	2,135	0.00	0.00	779,389	1.46	1.46	0.71
762	Gas Urban Buses (UB)	166	0.02	0.02	60,654	8.40	6.94	0.06
770	School Buses (SB)	337	0.00	0.00	122,995	1.46	1.46	0.11
776	Other Buses (OB)	927	0.00	0.00	338,430	0.73	0.73	0.31
780	Motor Homes (MH)	568	0.03	0.04	207,431	11.0	14.6	0.19
Total On-Road Motor Vehicles		**217,480**	**6.11**	**8.26**	**79,380,188**	**155**	**187**	**72.7**
Other Mobile Sources								
810	Aircraft	37,455	0.10	0.09	13,670,930	36.5	31.8	12.4
820	Trains	586	0.00	0.00	213,835	0.45	1.38	0.19
830	Ships and Commercial Boats	3,452	0.01	0.02	1,259,927	2.64	8.13	1.14
	Other Off-road sources (construction equipment, airport equipment, oil and gas drilling equipment)	16,080	1.72	8.84	5,869,123	628	3,226	5.56
Total Other Mobile Sources		**57,572**	**1.83**	**8.95**	**21,013,816**	**668**	**3,268**	**19.3**
Total Stationary and Area Sources		**176,388**	**0.49**	**626**	**64,381,716**	**178**	**228,639**	**63**
Total On-Road Vehicles		**217,480**	**6.11**	**8.26**	**79,380,188**	**155**	**187**	**73**
Total Other Mobile*		**57,572**	**1.83**	**8.95**	**21,013,816**	**668**	**3,268**	**19**
Total 2008 Baseline GHG Emissions for Basin		**451,440**	**8.42**	**644**	**164,775,719**	**1,001**	**232,094**	**155**

State

AB 32 - Global Warming Solutions Act: Some ODSs exhibit high global warming potentials. CARB developed a cap and trade regulation under AB 32. The cap and trade regulation includes the Compliance Offset Protocol Ozone Depleting Substances Projects, which provides methods to quantify and report GHG emission reductions associated with the destruction of high global warming potential ODS sourced from and destroyed within the U.S. that would have otherwise been released to the atmosphere. The protocol must be used to quantify and report GHG reductions under the ARB's GHG Cap and Trade Regulation.

Refrigerant Management Program: As part implementing AB 32, CARB also adopted a Refrigerant Management Program in 2009. The Refrigerant Management Program is designed to reduce GHG emissions from stationary sources through refrigerant leak detection and monitoring, leak repair, system retirement and retrofitting, reporting and recordkeeping, and proper refrigerant cylinder use, sale, and disposal.

HFC Emission Reduction Measures for Mobile Air Conditioning - Regulation for Small Containers of Automotive Refrigerant: The Regulation for Small Containers of Automotive Refrigerant applies to the sale, use, and disposal of small containers of automotive refrigerant with a GWP greater than 150. Emission reductions are achieved through implementation of four requirements: 1) use of a self-sealing valve on the container, 2) improved labeling instructions, 3) a deposit and recycling program for small containers, and 4) an education program that emphasizes best practices for vehicle recharging. This regulation went into effect on January 1, 2010 with a one-year sell-through period for containers manufactured before January 1, 2010. The target recycle rate is initially set at 90 percent, and rose to 95 percent beginning January 1, 2012.

SCAQMD

The SCAQMD adopted a "Policy on Global Warming and Stratospheric Ozone Depletion" on April 6, 1990. The policy targeted a transition away from CFCs as an industrial refrigerant and propellant in aerosol cans. In March 1992, the SCAQMD Governing Board reaffirmed this policy and adopted amendments to the policy to include the following directives for ODSs:

- phase out the use and corresponding emissions of CFCs, methyl chloroform (1,1,1-trichloroethane or TCA), carbon tetrachloride, and halons by December 1995;
- phase out the large quantity use and corresponding emissions of HCFCs by the year 2000;
- develop recycling regulations for HCFCs; and
- develop an emissions inventory and control strategy for methyl bromide.

SCAQMD Rule 1122 – Solvent Degreasers: SCAQMD Rule 1122 applies to all persons who own or operate batch-loaded cold cleaners, open-top vapor degreasers, all types of conveyorized degreasers, and air-tight and airless cleaning systems that carry out solvent degreasing operations with a solvent containing VOCs or with a NESHAP halogenated solvent. Some ODSs such as carbon tetrachloride and TCA are NESHAP halogenated solvents.

SCAQMD Rule 1171 – Solvent Cleaning Operations: SCAQMD Rule 1171 reduces emissions of VOCs, TACs, and stratospheric ozone-depleting or globalwarming compounds from the use, storage and disposal of solvent cleaning materials in solvent cleaning operations and activities

SCAQMD Rule 1411 - Recovery or Recycling of Refrigerants from Motor Vehicle Air Conditioners: Rule 1411 prohibits release or disposal of refrigerants used in motor vehicle air conditioners and prohibits the sale of refrigerants in containers which contain less than 20 pounds of refrigerant.

SCAQMD Rule 1415 - Reduction of Refrigerant Emissions from Stationary Air Conditioning Systems: Rule 1415 reduces emissions of high-global warming potential refrigerants from stationary air conditioning systems by requiring persons subject to this rule to reclaim, recover, or recycle refrigerant and to minimize refrigerant leakage.

SCAQMD Rule 1418 - Halon Emissions from Fire Extinguishing Equipment: Rule 1418 reduce halon emissions by requiring the recovery and recycling of halon from fire extinguishing systems, by limiting the use of halon to specified necessary applications, and by prohibiting the sale of portable halon fire extinguishers that contain less than five pounds of halon.

CHAPTER 4

ENVIRONMENTAL IMPACTS

INTRODUCTION

The CEQA Guidelines require environmental documents to identify significant environmental effects that may result from a proposed project [CEQA Guidelines §15126.2 (a)]. Direct and indirect significant effects of a project on the environment should be identified and described, with consideration given to both short- and long-term impacts. The discussion of environmental impacts may include, but is not limited to: the resources involved; physical changes; alterations of ecological systems; health and safety problems caused by physical changes; and, other aspects of the resource base, including water, scenic quality, and public services. If significant adverse environmental impacts are identified, the CEQA Guidelines require a discussion of measures that could either avoid or substantially reduce any adverse environmental impacts to the greatest extent feasible [CEQA Guidelines §15126.4].

The CEQA Guidelines indicate that the degree of specificity required in a CEQA document depends on the type of project being proposed [CEQA Guidelines §15146]. The detail of the environmental analysis for certain types of projects cannot be as great as for others. Accordingly, this ~~Draft~~Final SEA analyzes impacts on a regional level and impacts on the level of individual industries or individual facilities only where feasible.

The categories of environmental impacts to be studied in a CEQA document are established by CEQA [Public Resources Code, §21000 et seq.], and the CEQA Guidelines, as promulgated by the State of California Secretary of Natural Resources. Under the CEQA Guidelines, there are approximately 17 environmental categories in which potential adverse impacts from a project are evaluated. The Initial Study evaluated the project against the environmental categories to determine those environmental categories that may be adversely affected by the proposed project, which will be further analyzed in the appropriate CEQA document.

POTENTIAL ENVIRONMENTAL IMPACTS AND MITIGATION MEASURES

Pursuant to CEQA, an Initial Study, including an environmental checklist, was prepared for this project (see Appendix C). Of the 17 potential environmental impact categories, one topic (air quality and greenhouse gases) was identified as being potentially adversely affected by the proposed project for potential foregone air quality emission reductions. No comment letters were received during the 30-day public comment period for the Initial Study.

The topic of air quality emissions is further evaluated in detail in this ~~Draft~~Final SEA. The environmental impact analysis for this environmental topic incorporates a "worst-case" approach. This approach entails the premise that whenever the analysis requires that assumptions be made, those assumptions that result in the greatest adverse impacts are typically chosen. This method ensures that all potential effects of the proposed project are documented for the decision-makers and the public. Accordingly, the following analyses use a conservative "worst-case" approach for analyzing the potentially significant adverse environmental impacts associated with the implementation of the proposed project.

AIR QUALITY AND GHG EMISSIONS

The initial evaluation in the NOP/IS (see Appendix C) identified the topic of air quality and greenhouse gases as potentially being adversely affected by the proposed project. The proposed amendments to Rule 1110.2 will allow biogas engines additional time to comply with the emission limits in the current rule, as well as include limits on the number of breakdowns and emissions during those events to be consistent with EPA's breakdown provisions. In order to ensure a "worst-case" analysis, this analysis does not quantify or take credit for the reduction in emissions from the breakdown provisions. For purposes of this analysis, the affected equipment consists of biogas engines. This equipment is currently regulated by SCAQMD Rule 1110.2 – Emissions from Gaseous- and Liquid- Fueled Engines. Due to the fact that control technologies have not matured in a timely manner to retrofit biogas engines, the proposed project would place the affected equipment on a more suitable compliance schedule with achievable emission limitations under a new proposed rule.

Significance Criteria

To determine whether air quality impacts from adopting and implementing the proposed project are significant, impacts will be evaluated and compared to the following criteria. If impacts exceed any of the significance thresholds in Table 4-1, they will be considered significant. All feasible mitigation measures will be identified and implemented to reduce significant impacts to the maximum extent feasible. The proposed project will be considered to have significant adverse air quality impacts if any one of the thresholds in Table 4-1 are equaled or exceeded.

The SCAQMD makes significance determinations for construction impacts based on the maximum or peak daily emissions during the construction period, which provides a "worst-case" analysis of the construction emissions. Similarly, significance determinations for operational emissions are based on the maximum or peak daily allowable emissions during the operational phase.

Table 4-1
SCAQMD Air Quality Significance Thresholds

Mass Daily Thresholds [a]		
Pollutant	**Construction [b]**	**Operation [c]**
NOx	100 lbs/day	55 lbs/day
VOC	75 lbs/day	55 lbs/day
PM10	150 lbs/day	150 lbs/day
PM2.5	55 lbs/day	55 lbs/day
SOx	150 lbs/day	150 lbs/day
CO	550 lbs/day	550 lbs/day
Lead	3 lbs/day	3 lbs/day

Toxic Air Contaminants (TACs), Odor, and GHG Thresholds	
TACs (including carcinogens and non-carcinogens)	Maximum Incremental Cancer Risk ≥ 10 in 1 million Cancer Burden > 0.5 excess cancer cases (in areas ≥ 1 in 1 million) Chronic & Acute Hazard Index ≥ 1.0 (project increment)
Odor	Project creates an odor nuisance pursuant to SCAQMD Rule 402
GHG	10,000 MT/yr CO2eq for industrial facilities
Ambient Air Quality Standards for Criteria Pollutants [d]	
NO2 1-hour average annual arithmetic mean	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 0.18 ppm (state) 0.03 ppm (state) and 0.0534 ppm (federal)
PM10 24-hour average annual average	 10.4 $\mu g/m^3$ (construction)[e] & 2.5 $\mu g/m^3$ (operation) 1.0 $\mu g/m^3$
PM2.5 24-hour average	 10.4 $\mu g/m^3$ (construction)[e] & 2.5 $\mu g/m^3$ (operation)
Ambient Air Quality Standards for Criteria Pollutants [d]	
SO2 1-hour average 24-hour average	 0.25 ppm (state) & 0.075 ppm (federal – 99th percentile) 0.04 ppm (state)
Sulfate 24-hour average	 25 $\mu g/m^3$ (state)
CO 1-hour average 8-hour average	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 20 ppm (state) and 35 ppm (federal) 9.0 ppm (state/federal)
Lead 30-day Average Rolling 3-month average	 1.5 $\mu g/m^3$ (state) 0.15 $\mu g/m^3$ (federal)

[a] Source: SCAQMD CEQA Handbook (SCAQMD, 1993)
[b] Construction thresholds apply to both the South Coast Air Basin and Coachella Valley (Salton Sea and Mojave Desert Air Basins).
[c] For Coachella Valley, the mass daily thresholds for operation are the same as the construction thresholds.
[d] Ambient air quality thresholds for criteria pollutants based on SCAQMD Rule 1303, Table A-2 unless otherwise stated.
[e] Ambient air quality threshold based on SCAQMD Rule 403.

KEY: lbs/day = pounds per day; ppm = parts per million; $\mu g/m^3$ = microgram per cubic meter; ≥ = greater than or equal to; MT/yr CO2eq = metric tons per year of CO2 equivalents; > = greater than

Project-Specific Air Quality and GHG Emissions Impacts

PAR 1110.2 impacts 55 biogas engines located throughout the SCAQMD jurisdiction (see Figure 2-1). The proposed project will delay the compliance date of the emission limit requirements (see Table 4-2). These engines will be subject to add-on control equipment in order to comply with the new emission limits. Construction-related impacts were previously analyzed in the December 2007 EA and no changes are expected at this time; therefore, the impacts associated with construction and installation of the control equipment will not be analyzed here. See Chapter 4 of the December 2007 EA[1] for a more detailed description and calculations of emissions.

The emissions affected by the proposed project and delay of emission reductions are nitrogen oxides (NOx), carbon monoxide (CO), and volatile organic compounds (VOCs). Emissions of particulate matter (PM10), and sulfur oxides (SOx) are not expected to change compared with the analysis done in the December 2007 EA because the control equipment does not affect any of these emissions. Any potential air quality impact from the proposed rule is considered in this CEQA analysis.

Since the amendments to Rule 1110.2 on September 7, 2012, SCAQMD staff has met with the stakeholders periodically, both in public forums and through individual meetings for updates on technology implementation. Based on feedback from these operators, some installations will take longer to install than expected and will reach full compliance after the current deadline of January 1, 2016. The range of implementation dates ranged from about mid-2016 to mid-2018.

Operators of affected biogas operations would be required to comply with the concentration limits in Table 4-2 by January 1, 2017.

Table 4-2

Proposed Concentration Limits for Biogas Engines

Concentration Limits Effective January 1, 2017		
NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
11	30	250

[1]Corrected to 15 percent oxygen on a dry basis and averaged over 15 minutes.
[2]Measured as carbon, corrected to 15 percent oxygen on a dry basis and averaged over required sampling time.

For the City of San Bernardino and Eastern Municipal Water District that commenced and implemented technology demonstration projects prior to January 1, 2015, all of their biogas engines would have until January 1, 2018 to comply with the requirements of Table 4-2.

The proposed project would delay the compliance dates outlined in Rule 1110.2, and therefore, there would be adjustments to the annual operational NOx, CO and VOC emission reductions during the varying compliance years. Table 4-3 summarizes the amount of emission reductions from the proposed project compared to current Rule 1110.2.

1 http://www.aqmd.gov/home/library/documents-support-material/lead-agency-scaqmd-projects/aqmd-projects---year-2008/fea-for-par-1110-2

Table 4-3
PAR 1110.2 Delayed emissions

Compliance Extension	*Type of Project*	*NOx (tpd)*	*VOC (tpd)*	*CO (tpd)*
January 1, 2017	Emission Reductions delayed for January 1, 2017 Compliance Date (non-demonstration project ICEs)	~~0.87~~0.63	~~0.39~~0.19	~~18.25~~16.25
January 1, 2018	Emission Reductions delayed for January 1, 2018 Compliance Date (demonstration project ICEs)	~~0.04~~0.28	~~0.09~~0.29	~~1.75~~3.75
	Total	**0.9**	**0.5**	**20**
	CEQA Operating Significance Thresholds	**0.0275**	**0.0275**	**0.275**

Since the Draft SEA was released for public review and comment, OCSD staff contacted SCAQMD staff and requested that the OCSD project be classified as a "demonstration project", which gives OCSD an additional year to comply with the requirements of PAR 1110.2. In doing so, the emissions reductions delayed from the OCSD project would shift from 2017 to 2018. Since the SCAQMD's CEQA significance thresholds are based on a maximum daily emissions limit, the maximum emissions foregone from PAR 1110.2 do not change with the re-designation of the OCSD project to "demonstration project", as shown in Table 4-3 above. Therefore, this revision does not alter any conclusions reached in the Draft SEA, nor provide new information of substantial importance relative to the draft document. As a result, this revision does not require recirculation of the document pursuant to CEQA Guidelines §15073.5.

NOx, CO, and VOC emission reductions for PAR 1110.2 are delayed over time compared with Rule 1110.2, but these emissions are not permanently foregone. The quantity of peak daily NOx, CO, and VOC emission reductions delayed exceeds the SCAQMD's CEQA significance thresholds for operation. Thus, PAR 1110.2 will result in adverse significant operational air quality impacts.

GHG Emissions Impacts

Since GHG emissions are based on fuel usage, the GHG emissions will remain the same no matter the type of combustion source. Because the add-on control equipment controls only NOx, CO, and VOC, there are no expected reductions in GHG emissions. As shown in Figure 4-1, a SCR controls NOx. Figure 4-2 shows a SNCR (NOx Tech System) controlling NOx.

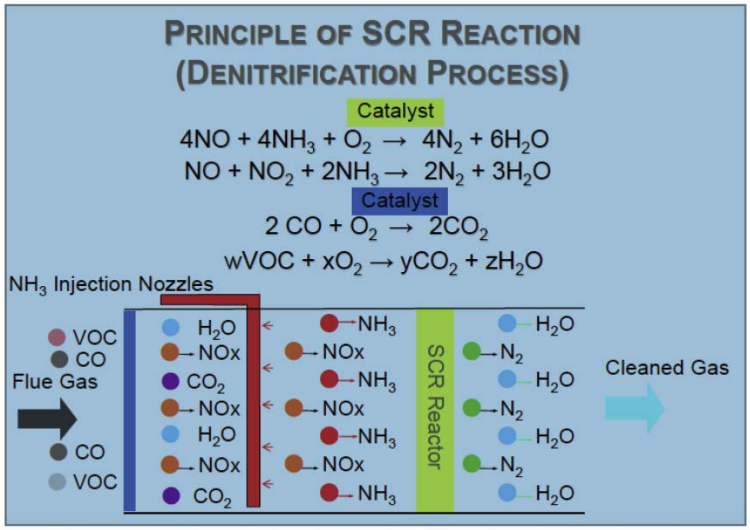

Figure 4-1: Principle of SCR Reaction

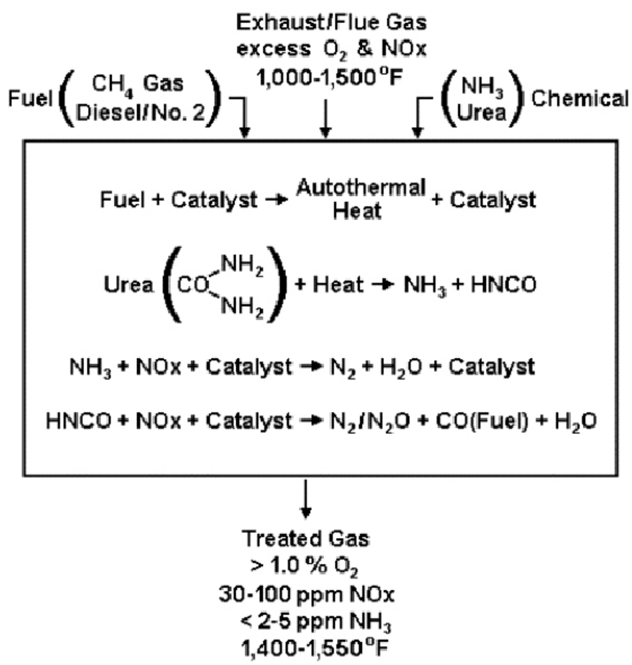

Figure 4-2: Principle of SNCR reaction

As for oxidation catalysts, in most gas streams, carbon monoxide (CO) and hydrocarbons (HC) or VOCs can be removed by combination with oxygen (O_2) using an oxidation catalyst (also known as a 2-way catalyst):

$$CO + \frac{1}{2} O_2 \rightarrow CO_2$$
$$[HC] + O_2 \rightarrow CO_2 + H_2O$$

BIOHALO ENGINES

6 Engines are currently being retrofitted with biohalo technology. Biohalo can reduce GHG, but because the City of San Bernardino is still in the testing and demonstration stage, there is no

available data to quantify GHG reductions. A worst-case scenario is that the GHG emissions will be the same.

Project-Specific Mitigation for Air Quality and GHG Emissions Impacts

As concluded above, the air quality analysis for the proposed project indicates that NOx, CO, and VOC emission reductions delayed during operation exceed the applicable operational significance threshold and are considered to be significant (see Table 4-3). GHG Emissions are not impacted, see previous "GHG Emissions Impacts" paragraph for explanation. If significant adverse environmental impacts are identified in a CEQA document, the CEQA document shall describe feasible measures that could minimize the impacts of the proposed project. PAR 1110.2 is a compliance date adjustment to the rule and alternatives to the project are no project, adjustments to the compliance dates, installing new flares, or installing new micro turbines, which are addressed in the alternatives analysis found in Chapter 5.

PAR 1110.2 also includes options for an alternate compliance option with payment of a compliance flexibility fee to further delay compliance. The alternate compliance option provides facilities additional time to phase in compliance over one year. However, the air quality analysis presented above represents a "worst-case" analysis and accounts for these potential additional delays in compliance (as shown in Table 4-3). It would be speculative to guess which non-demonstration project facilities will elect to delay an additional year until January 1, 2018. It would be also speculative to guess which demonstration projects will elect to delay until January 1, 2019. A "worst-case scenario", would be that all of the projects extend their compliance date by an additional year. However, the CEQA SCAQMD Significance thresholds are based on a daily limit. Therefore, the environmental impacts would remain the same.

The mitigation fee option for PAR 1110.2 is the same compliance flexibility mitigation fee program that currently exists in Rule 1110.2 and is available to the affected sources, except that it is extended by one year. In Rule 1110.2, all mitigation fees are used to reduce NOx emissions through the SCAQMD's leaf blower exchange program. The fees collected as a result of the implementation of PAR 1110.2 from the affected facilities electing to use the mitigation fee option will be used in the same manner as fees collected for Rule 1110.2. By funding this program, emission reductions will be generated that provide a regional air quality improvement to reduce the impact from the potential delay in emission reductions from those facilities choosing to delay compliance. It is possible that the use of these fees will fully offset the adverse air quality impact, but this cannot be foreseen at this time. There are no further feasible mitigation measures identified at this time that would reduce or eliminate the expected delay in emission reductions. Consequently, the operational air quality emissions impacts from the proposed project cannot be mitigated to less than significant. Therefore, Findings and a Statement of Overriding Considerations will be prepared for the Governing Board's consideration and approval prior to the public hearings for the proposed amendments. Impacts from implementing the mitigation option were analyzed as part of the environmental assessment conducted for PAR 1110.2 in 2008 (http://www.aqmd.gov/home/library/documents-support-material/lead-agency-scaqmd-projects/aqmd-projects---year-2008/fea-for-par-1110-2) and will not change as a result of PAR 1110.2. Because the affected facilities are located throughout the SCAQMD jurisdiction, localized impacts cannot be determined at this level of analysis.

Remaining Air Quality and GHG Emissions Impacts

The air quality analysis concluded that significant adverse operational air quality impacts could be created by the proposed amendments because approximately 0.9 tons per day of NOx, 0.5 tons per day of VOC, and 20 tons per day of CO emission reductions will be delayed.

Cumulative Air Quality and GHG Emissions Impacts

The preceding project-specific analysis concluded that air quality emissions impacts during operation could be significant from implementing the proposed project. Specifically, delaying NOx, CO, and VOC emission reductions could exceed the SCAQMD's significance threshold for operation. The delay does not affect any GHG reductions, see "GHG Emissions Impacts" paragraph as previously discussed in this Chapter. Thus, the air quality emissions impacts during operation are considered to be cumulatively considerable pursuant to CEQA Guidelines §15064 (h)(1). It should be noted, however, that the air quality analysis is a conservative, "worst-case" analysis so the actual operation impacts may not be as great as estimated here if facility operators meet the compliance schedule earlier than planned.

Even though the proposed project could result in significant adverse project-specific impacts in delaying emission reductions during operation, they are not expected to interfere with the air quality progress and attainment demonstration projected in the 2012 AQMP. Further, based on regional modeling analyses performed for the 2012 AQMP, implementing control measures contained in the 2012 AQMP, in addition to the air quality benefits of existing rules with future compliance dates, it is anticipated to bring the district into attainment with all national and most state ambient air quality standards by the year 2014 for the federal 24-hour PM2.5 standard and by the year 2023 for the federal eight-hour ozone standard.

The 2012 AQMP anticipated attainment of the 2006 federal 24-hour PM2.5 standard by 2014, but a Supplement to the 2012 AQMP demonstrated compliance by 2015. Verified preliminary PM2.5 data for 2015, however, supported the need to request a "bump up" in the non-attainment designation to "serious" shifting the attainment to 2019 (10 years since the designation on December 14, 2009). The 1997 federal 8-hour ozone (at 80 ppb) is expected to demonstrate attained in 2023 to meet the standard attainment date of June 15, 2024. The proposed delay in emission reductions is expected to be temporary and the affected industries are expected to comply by 2017 before the attainment demonstration years for the 2006 24-hour PM2.5 and 1997 8-hour ozone (80 ppb) of 2019 and 2023, respectively. Thus, so no adverse impact on the progress or attainment demonstration. However, the rate of further progress (time between the base year and the attainment date) would be temporarily adversely affected but other emission reductions are taking place (e.g., annual fleet turnover) that would offset the temporary delay in emission reductions, thus not significant. The upcoming 2016 AQMP will be demonstrating attainment of the 2008 8-hour ozone standard (75 ppb) and 2012 annual PM2.5 standard (12 ug/m3) by 2032 and 2025, respectively, which are beyond the year affected (2016) by the delay in rule compliance and delay of emission reductions.

Cumulative Mitigation Measures

The analysis indicates that the proposed project could result in a delay of NOx, VOC, and CO emission reductions during operation of the proposed project, and the delay would result in permanent adverse significant cumulative air quality emissions impacts. However, the compliance delay is temporary and the emissions would be recaptured in the future compliance years. There are no feasible mitigation measures which could be included to reduce the cumulative impact of the project. Thus, PAR 1110.2 will result in adverse significant cumulative air quality impacts.

HEALTH EFFECTS ANALYSIS

Ozone formation is primarily the result of the two criteria pollutants, volatile organic compounds (VOCs) and nitrous oxides (NOx), mixing with sunlight to create a chemical reaction. The proposed project will generate significant delayed NOx, VOC, and CO emissions, thus temporarily forego the health benefit from NOx, VOC, and CO emission reductions originally expected under Rule 1110.2 from the affected sources. Because the affected facilities are located throughout the SCAQMD jurisdiction, localized health effects could not be determined at this level of analysis. However, due to extensive knowledge of the health effects from ozone and localized studies of those effects, the following analysis is to assist in determining, qualitatively, the health effects from the significant operational NOx, VOC, and CO emissions impacts.

Ozone is a highly reactive compound, and is a strong oxidizing agent. When ozone comes into contact with the respiratory tract, it can react with tissues and cause damage in the airways. Since it is a gas, it can penetrate into the gas exchange region of the deep lung.

The U.S. EPA primary federal standard for ozone, adopted in 2008, is 75 ppb averaged over eight hours. The California Air Resources Board (CARB) has established state standards of 90 ppb averaged over one hour and at 70 ppb averaged over eight hours. The approved 2007 Air Quality Management Plan (AQMP) provides a blueprint as to how and when the SCAQMD will attain the 1997 8-hour ozone standard (80 ppb) by year 2023, and the upcoming 2016 AQMP will propose a control strategy to be implemented to demonstrate attainment of the 75 ppb 8-hour ozone standard by 2032.

A number of population groups are potentially at increased risk for ozone exposure effects. In the ongoing review of ozone, the U.S. EPA has identified populations as having adequate evidence for increased risk from ozone exposures, including individuals with asthma, younger and older age groups, and individuals with reduced intake of certain nutrients such as Vitamins C and E, and outdoor workers. There is suggestive evidence for other potential factors, such as variations in genes related to oxidative metabolism or inflammation, gender, socioeconomic status, and obesity. However further evidence is needed.

The adverse effects reported with short-term ozone exposure are greater with increased activity because activity increases the breathing rate and the volume of air reaching the lungs, resulting in an increased amount of ozone reaching the lungs. Children may be a particularly vulnerable population to air pollution effects because they spend more time outdoors, are generally more active, and have a higher specific ventilation rate than adults (i.e. after normalization for body mass).

A number of adverse health effects associated with ambient ozone levels have been identified from laboratory and epidemiological studies[2]. These include increased respiratory symptoms, damage to cells of the respiratory tract, decrease in lung function, increased susceptibility to respiratory infection, an increased risk of hospitalization, and increased risk of mortality.

[2] U.S. EPA. (2006) Air Quality Criteria for Ozone and Related Photochemical Oxidants (2006 Final). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-05/004aF-cF

[2] American Thoracic Society (ATS), Committee of the Environmental and Occupational Health Assembly of the American Thoracic Society. (1996). "Health Effects of Outdoor Air Pollution." American Journal Respiratory and Critical Care Medicine, Parts 1 and 2. 153:3-50 and 153:477-498

Increases in ozone levels are associated with increased numbers of absences from school. The Children's Health Study, conducted by researchers at the University of Southern California, followed a cohort of children that live in 12 communities in Southern California with differing levels of air pollution for several years. A publication from this study reported that school absences in fourth graders for respiratory illnesses were positively associated with ambient ozone levels. An increase of 20 ppb ozone was associated with an 83% increase in illness-related absence rates[3].

The number of hospital admissions and emergency room visits for all respiratory causes (infections, respiratory failure, chronic bronchitis, etc.) including asthma shows a consistent increase as ambient ozone levels increase in a community. These excess hospital admissions and emergency room visits are observed when hourly ozone concentrations are as low as 60 to 100 ppb.

Numerous recent studies have found positive associations between increases in ozone levels and excess risk of mortality. These associations are strongest during warmer months but overall persist even when other variables including season and levels of particulate matter are accounted for. This indicates that ozone mortality effects may be independent of other pollutants[4].

Multicity studies of short-term ozone exposures (days) and mortality have also examined regional differences. Evidence was provided that there were generally higher ozone-mortality risk estimates in northeastern U.S. cities, with the southwest and urban mid-west cities showing lower or no associations[5]. Another long-term study of a national cohort found that long-term exposures to ozone were associated with respiratory-related causes of mortality, but not cardiovascular-related causes, when PM2.5 exposure was also included in the analysis.

In the ongoing U.S. EPA review, it was concluded that there is adequate evidence for asthmatics to be a potentially at risk population[6]. Several population-based studies suggest that asthmatics are at risk from ambient ozone levels, as evidenced by changes in lung function, increased hospitalizations and emergency room visits.

Laboratory studies have also compared the degree of lung function change seen in age and gender-matched healthy individuals versus asthmatics and those with chronic obstructive pulmonary disease. In studies of individuals with chronic obstructive pulmonary decease, the degree of change evidenced did not differ significantly. That finding, however, may not accurately reflect the true impact of exposure on these respiration-compromised individuals. Since the respiration-compromised group may have lower lung function to begin with, the same total change may represent a substantially greater relative adverse effect overall. Other studies have found that

---

3 Gilliland FD, Berhane K, Rappaport EB, Thomas DC, Avol E, Gauderman WJ, London SJ, Margolis HG, McConnell R, Islam KT, Peters JM. (2001). "The Effects of Ambient Air Pollution on School Absenteeism Due to Respiratory Illnesses." Epidemiology, 12(1):43-54.

4 Bell ML, McDermott A, Zeger SL, Samet, JM, Dominici, F. (2004). "Ozone and Short-Term Mortality in 95 US Urban Communities, 1987-2000." JAMA 292:2372-2378.

5 Smith, RL; Xu, B; Switzer, P. (2009). Reassessing the relationship between ozone and short-term mortality in U.S. urban communities. Inhal Toxicol 21: 37-61;

5 Bell, ML; Dominici, F. (2008). Effect modification by community characteristics on the short-term effects of ozone exposure and mortality in 98 US communities. Am J Epidemiol 167: 986-997.

6 U.S. EPA. (2012) Integrated Science Assessment of Ozone and Related Photochemical Oxidants (Third External Review Draft). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-10/076C

subjects with asthma are more sensitive to the short-term effects of ozone in terms of lung function and inflammatory response.

Another publication from the Children's Health Study focused on children and outdoor exercise. In Southern California communities with high ozone concentrations, the relative risk of developing asthma in children playing three or more sports was found to be over three times higher than in children playing no sports[7]. These findings indicate that new cases of asthma in children may be associated with performance of heavy exercise in communities with high levels of ozone. While it has long been known that air pollution can exacerbate symptoms in individuals with preexisting respiratory disease, this is among the first studies that indicate ozone exposure may be causally linked to asthma onset.

The evidence linking these effects to air pollutants is derived from population-based observational and field studies (epidemiological) as well as controlled laboratory studies involving human subjects and animals. There have been an increasing number of studies focusing on the mechanisms (that is, on learning how specific organs, cell types, and biomarkers are involved in the human body's response to air pollution) and specific pollutants responsible for individual effects.

In addition, human and animal studies involving both short-term (few hours) and long-term (months to years) exposures indicate a wide range of effects induced or associated with ambient ozone exposure. These are summarized in Table 4-4.

Some lung function responses (volume and airway resistance changes) observed after a single exposure to ozone exhibit attenuation or a reduction in magnitude with repeated exposures. Although it has been argued that the observed shift in response is evidence of a probable adaptation phenomenon, it appears that while functional changes may exhibit attenuation, biochemical and cellular changes which may be associated with episodic and chronic exposure effects may not exhibit similar adaptation. That is, internal damage to the respiratory system may continue with repeated ozone exposures, even if externally observable effects (chest symptoms and reduced lung function) disappear. Additional argument against adaptation is that after several days or weeks without ozone exposures, the responsiveness in terms of lung function as well as symptoms returns.

In a laboratory, exposure of human subjects to low levels of ozone causes reversible decrease in lung function as assessed by various measures such as respiratory volumes, airway resistance and reactivity, irritative cough and chest discomfort. Lung function changes have been observed with ozone exposure as low as 60 to 120 ppb for 6-8 hours under moderate exercising conditions. Similar lung volume changes have also been observed in adults and children under ambient exposure conditions (100 - 150 ppb 1-hour average). The responses reported are indicative of decreased breathing capacity and are reversible.

[7] McConnell R, Berhane K, Gilliland F, London SJ, Islam T, Gauderman WJ, Avol E, Margolis HG, Peters JM. (2002). "Asthma in exercising children exposed to ozone: a cohort study." Lancet, 359:386-91.

Table 4 -4

Adverse Health Effects of Ozone (O3) - Summary of Key Findings

OZONE CONCENTRATION AND EXPOSURE (ppm, hr)	HEALTH EFFECT
Ambient air containing 0.10 - 0.15 ppm daily 1-hr max over days to weeks; < 0.06 ppm (Max 8-hour average) < 0.069 ppm (Mean 8-hour average)	Decreased breathing capacity in children, adolescents, and adults exposed to O3 outdoors. Positive associations of ambient O3 with respiratory hospital admissions and Emergency Department (ED) visits in the U.S., Europe, and Canada with supporting evidence from single-city studies. Generally, these studies had mean 8-h max O3 concentrations less than 0.06 ppm. Positive associations between short-term exposure to ambient O3 and respiratory symptoms (e.g., cough, wheeze, and shortness of breath) in children with asthma. Generally, these studies had mean 8-hr max O3 concentrations less than 0.069 ppm.
≥0.12 ppm (1-3hr) ≥0.06 ppm (6.6hr) (chamber exposures)	Decrements in lung function (reduced ability to take a deep breath), increased respiratory symptoms (cough, shortness of breath, pain upon deep inspiration), increased airway responsiveness and increased airway inflammation in exercising adults. Effects are similar in individuals with preexisting disease except for a greater increase in airway responsiveness for asthmatic and allergic subjects. Older subjects (>50 yrs old) have smaller and less reproducible changes in lung function. Attenuation of response with repeated exposure.
≥0.12 ppm with prolonged, repeated exposure (chamber exposures)	Changes in lung structure, function, elasticity, and biochemistry in laboratory animals that are indicative of airway irritation and inflammation with possible development of chronic lung disease. Increased susceptibility to bacterial respiratory infections in laboratory animals.

From: U.S. EPA. (2012) Integrated Science Assessment of Ozone and Related Photochemical Oxidants (Third External Review Draft). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-10/076C

The results of several studies where human volunteers were exposed to ozone for 6.6 hours at levels between 40 and 120 ppb were recently summarized[8].

In addition to controlled laboratory conditions, studies of individuals exercising outdoors, including children attending summer camp, have shown associations of reduced lung function with ozone exposure. There were wide ranges in responses among individuals. U.S. EPA's recent review indicates reductions of <1 to 4% in lung function when standardized to an increase of 30 ppb for an 8-hour maximum[9].

---

[8] Brown JS, Bateson TF, McDonnell WF (2008). Effects of Exposure to 0.06 ppm Ozone on FEV1 in Humans: A Secondary Analysis of Existing Data. Environ Health Perspect 116:1023-1026.

[9] U.S. EPA. (2012) Integrated Science Assessment of Ozone and Related Photochemical Oxidants (Third External Review Draft). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-10/076C.

Results of epidemiology studies support the relationship between ozone exposure and respiratory effects. Several, but not all, studies have found associations of short-term ozone levels and hospital admissions and emergency department admissions for respiratory-related conditions[10].

In laboratory studies, cellular and biochemical changes associated with respiratory tract inflammation have also been consistently found in the airway lining after low- level exposure to ozone. These changes include an increase in specific cell types and in the concentration of biochemical mediators of inflammation and injury such as Interleukin-1, Tumor Necrosis Factor α, and fibronectin. Indications of lung injury and inflammatory changes have been observed in healthy adults exposed to ozone in the range of 60 to 100 ppb for up to 6.6 hours with intermittent moderate exercise.

There may be interactions between ozone and other ambient pollutants. The susceptibility to ozone observed under ambient conditions could be modified due to the combination of pollutants that coexist in the atmosphere or ozone might sensitize these subgroups to the effects of other pollutants.

Some animal studies show results that indicate possible chronic effects including functional and structural changes of the lung. These changes indicate that repeated inflammation associated with ozone exposure over a lifetime may result in cumulative damage to respiratory tissue such that individuals later in life may experience a reduced quality of life in terms of respiratory function and activity level achievable. An autopsy study involving Los Angeles County residents, although conducted many years ago when pollutant levels were higher than currently measured, provided supportive evidence of lung tissue damage (structural changes) attributable to air pollution.

A study of birth outcomes in Southern California found an increased risk for birth defects in the aortic and pulmonary arteries associated with ozone exposure in the second month of pregnancy[11]. This was the first study linking ambient air pollutants to birth defects in humans. Studies conducted since mostly focusing on cardiac and oral cleft defects have found mixed results, with some showing associations, but others did not.

In summary, adverse effects associated with ozone exposures have been well documented. Although the specific mechanisms of actions are not fully identified, there is a strong likelihood that oxidation of key enzymes and proteins and inflammatory responses play important roles.

U.S. EPA staff has provided conclusions on the causality on ozone health effects for the health outcomes[12] evaluated (provided in Tables 4-5 and 4-6). To understand the meaning of the causal relationship between air pollution and health, Table 4-5 below shows the five descriptors used by U.S. EPA.

The proposed project's impacts are short-term (maximum of 2 year delay) and no long-term health effects are expected.

---

[10] U.S. EPA (2012) Policy Assessment for the Review of the Ozone National Ambient Air Quality Standards First External Review Draft EPA–452/P–12–002, August 2012

[11] Ritz B, Yu F, Fruin S. Chapa G, Shaw GM, Harris JA. (2002). "Ambient Air Pollution and Risk of Birth Defects in Southern California." Am J Epidemiol, 155(1):17-25

[12] U.S. EPA. (2012) Integrated Science Assessment of Ozone and Related Photochemical Oxidants (Third External Review Draft). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-10/076C

Table 4 -5
Weight of Evidence Descriptions for Causal Determination

DETERMINATION	WEIGHT OF EVIDENCE
Causal Relationship	Evidence is sufficient to conclude that there is a causal relationship with relevant pollutant exposures. That is, the pollutant has been shown to result in health effects in studies in which chance, bias, and confounding could be ruled out with reasonable confidence. For example: a) controlled human exposure studies that demonstrate consistent effects; or b) observational studies that cannot be explained by plausible alternatives or are supported by other lines of evidence (e.g., animal studies or mode of action information). Evidence includes replicated and consistent high-quality studies by multiple investigators. Evidence is sufficient to conclude that there is a causal relationship with relevant pollutant exposures. That is, the pollutant has been shown to result in effects in studies in which chance, bias, and confounding could be ruled out with reasonable confidence. Controlled exposure studies (laboratory or small- to medium-scale field studies) provide the strongest evidence for causality, but the scope of inference may be limited. Generally, determination is based on multiple studies conducted by multiple research groups, and evidence that is considered sufficient to infer a causal relationship is usually obtained from the joint consideration of many lines of evidence that reinforce each other.
Likely To Be A Causal Relationship	Evidence is sufficient to conclude that a causal relationship is likely to exist with relevant pollutant exposures, but important uncertainties remain. That is, the pollutant has been shown to result in health effects in studies in which chance and bias can be ruled out with reasonable confidence but potential issues remain. For example: a) observational studies show an association, but copollutant exposures are difficult to address and/or other lines of evidence (controlled human exposure, animal, or mode of action information) are limited or inconsistent; or b) animal toxicological evidence from multiple studies from different laboratories that demonstrate effects, but limited or no human data are available. Evidence generally includes replicated and high-quality studies by multiple investigators.
Suggestive Of A Causal Relationship	Evidence is suggestive of a causal relationship with relevant pollutant exposures, but is limited because chance, bias and confounding cannot be ruled out. For example, at least one high-quality epidemiologic study shows an association with a given health outcome but the results of other studies are inconsistent.
Inadequate To Infer A Causa Relationship	Evidence is inadequate to determine that a causal relationship exists with relevant pollutant exposures. The available studies are of insufficient quantity, quality, consistency or statistical power to permit a conclusion regarding the presence or absence of an effect.
Not Likely To Be A Causal Relationship	Evidence is suggestive of no causal relationship with relevant pollutant exposures. Several adequate studies, covering the full range of levels of exposure that human beings are known to encounter and considering susceptible populations, are mutually consistent in not showing an effect at any level of exposure.

Adapted from U.S. EPA. (2009) Integrated Science Assessment for Particulate Matter (Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-08/139F

Table 4-6
Summary of Causal Determinations for Short-Term Exposures to Ozone

HEALTH CATEGORY	CAUSAL DETERMINATION
Respiratory Effects	Causal relationship
Cardiovascular Effects	Suggestive of a causal relationship
Central Nervous System Effects	Suggestive of a causal relationship
Effects on Liver and Xenobiotic Metabolism	Inadequate to infer a causal relationship
Effects on Cutaneous and Ocular Tissues	Inadequate to infer a causal relationship
Mortality	Likely to be a causal relationship

POTENTIAL ENVIRONMENTAL IMPACTS FOUND NOT TO BE SIGNIFICANT

While all the environmental topics required to be analyzed under CEQA were reviewed in the NOP/IS (see Appendix C) to determine if the proposed project could create significant impacts, the screening analysis concluded that the following environmental areas would not be significantly adversely affected by the proposed project: aesthetics, agriculture and forestry resources, biological resources, cultural resources, energy, geology and soils, hazards and hazardous materials, hydrology and water quality, land use and planning, mineral resources, noise, population and housing, public services, recreation, solid/hazardous waste, and transportation/traffic. Please refer to the NOP/IS in Appendix C for the detailed analysis and conclusions for the environmental topic impacts found to be not significant and not further analyzed.

SIGNIFICANT IRREVERSIBLE ENVIRONMENTAL CHANGES

CEQA Guidelines §15126 (c) requires an environmental analysis to consider "any significant irreversible environmental changes which would be involved if the proposed action should be implemented." This EA identified the topic of air quality during operation as the only environmental area potentially adversely affected by the proposed project.

Even though the proposed project could result in emission reductions foregone during operation that exceeds the applicable operational air quality significance threshold, they could for the following reasons not be expected to interfere with the air quality progress and attainment demonstration projected in the AQMP. Based on regional modeling analyses performed for the 2012 AQMP, implementing control measures contained in the 2012 AQMP, in addition to the air quality benefits of the existing rules, is anticipated to bring the district into attainment with all national and most state ambient air quality standards by the year 2023. Therefore, cumulative operational air quality impacts from the proposed project, previous amendments and all other AQMP control measures considered together, are not expected to be significant because implementation of all AQMP control measures is expected to result in net emission reductions and overall air quality improvement. This determination is consistent with the conclusion in the 2012 AQMP Final Program EIR that direct cumulative air quality impacts from all AQMP control measures are not expected to be significant (SCAQMD, 2012). For these reasons, the proposed project would not result in irreversible environmental changes or irretrievable commitment of resources.

POTENTIAL GROWTH-INDUCING IMPACTS

CEQA Guidelines §15126(d) requires an environmental analysis to consider the "growth inducing impact of the proposed action." Implementing the proposed project will not, by itself, have any direct or indirect growth-inducing impacts on businesses in the SCAQMD's jurisdiction because it is not expected to foster economic or population growth or the construction of additional housing and primarily affects existing food oven, roasting and smokehouse facilities.

CONSISTENCY

CEQA Guidelines §15125(d) requires an EIR to discuss any inconsistencies between a proposed project and any applicable general plans or regional plans. SCAG and the SCAQMD have developed, with input from representatives of local government, the industry community, public health agencies, the USEPA - Region IX and CARB, guidance on how to assess consistency within the existing general development planning process in the Basin. Pursuant to the development and adoption of its Regional Comprehensive Plan Guide (RCPG), SCAG has developed an Intergovernmental Review Procedures Handbook (June 1, 1995). The SCAQMD also adopted criteria for assessing consistency with regional plans and the AQMP in its CEQA Air Quality Handbook. The following sections address the consistency between the proposed project and relevant regional plans pursuant to the SCAG Handbook and SCAQMD Handbook.

Consistency with Regional Comprehensive Plan and Guide (RCPG) Policies

The RCPG provides the primary reference for SCAG’s project review activity. The RCPG serves as a regional framework for decision making for the growth and change that is anticipated during the next 20 years and beyond. The Growth Management Chapter (GMC) of the RCPG contains population, housing, and jobs forecasts, which are adopted by SCAG’s Regional Council and that reflect local plans and policies, shall be used by SCAG in all phases of implementation and review. It states that the overall goals for the region are to: 1) re-invigorate the region’s economy; 2) avoid social and economic inequities and the geographical isolation of communities; and, 3) maintain the region’s quality of life.

Consistency with Growth Management Chapter (GMC) to Improve the Regional Standard of Living

The Growth Management goals are to develop urban forms that enable individuals to spend less income on housing cost, that minimize public and private development costs, and that enable firms to be more competitive, strengthen the regional strategic goal to stimulate the regional economy. The proposed project in relation to the GMC would not interfere with the achievement of such goals, nor would it interfere with any powers exercised by local land use agencies. Further, the proposed project will not interfere with efforts to minimize red tape and expedite the permitting process to maintain economic vitality and competitiveness.

Consistency with Growth Management Chapter (GMC) to Provide Social, Political and Cultural Equity

The Growth Management goals to develop urban forms that avoid economic and social polarization promotes the regional strategic goals of minimizing social and geographic disparities and of reaching equity among all segments of society. Consistent with the Growth Management goals, local jurisdictions, employers and service agencies should provide adequate training and retraining of workers, and prepare the labor force to meet the challenges of the regional economy. Growth Management goals also include encouraging employment development in job-poor localities through support of labor force retraining programs and other economic development measures. Local jurisdictions and other service providers are responsible to develop sustainable communities and provide, equally to all members of society, accessible and effective services such as: public education, housing, health care, social services, recreational facilities, law enforcement, and fire protection. Implementing the proposed project has no effect on and, therefore, is not expected to interfere with the goals of providing social, political and cultural equity.

Consistency with Growth Management Chapter (GMC) to Improve the Regional Quality of Life

The Growth Management goals also include attaining mobility and clean air goals and developing urban forms that enhance quality of life, accommodate a diversity of life styles, preserve open space and natural resources, are aesthetically pleasing, preserve the character of communities, and enhance the regional strategic goal of maintaining the regional quality of life. The RCPG encourages planned development in locations least likely to cause environmental impacts, as well as supports the protection of vital resources such as wetlands, groundwater recharge areas, woodlands, production lands, and land containing unique and endangered plants and animals. While encouraging the implementation of measures aimed at the preservation and protection of recorded and unrecorded cultural resources and archaeological sites, the plan discourages development in areas with steep slopes, high fire, flood and seismic hazards, unless complying with special design requirements. Finally, the plan encourages mitigation measures that reduce noise in certain locations, measures aimed at preservation of biological and ecological resources, measures that could reduce exposure to seismic hazards, minimize earthquake damage, and develop emergency response and recovery plans. The proposed project has no impact on any of these issues except air quality. However, since the project would not interfere with the AQMP, it will not be inconsistent with the goal of improving the regional quality of life. Therefore, in relation to the GMC, the proposed project is not expected to interfere, but rather help with attaining and maintaining the air quality portion of these goals.

Consistency with Regional Mobility Element (RMP) and Congestion Management Plan (CMP)

PAR 1110.2 is consistent with the RMP and CMP since no significant adverse impact to transportation/circulation will result from the temporary delay of NOx emission reductions within the District. Because affected facilities will not increase their handling capacities, there will not be an increase in material transport trips associated with the implementation of PAR 1110.2. Therefore, PAR 1110.2 is not expected to adversely affect circulation patterns or congestion management.

CHAPTER 5

ALTERNATIVES

INTRODUCTION

This ~~Draft~~Final SEA provides a discussion of alternatives to the proposed project as required by CEQA. A range of reasonable alternatives to the proposed project shall include measures that feasibly attain most of the project objectives and provide a means for evaluating the comparative merits of each alternative. A 'no project' alternative must also be evaluated. The range of alternatives must be sufficient to permit a reasoned choice, but need not include every conceivable project alternative. CEQA Guidelines §15126.6 (c) specifically notes that the range of alternatives required in a CEQA document is governed by a 'rule of reason' and only necessitates that the CEQA document set forth those alternatives necessary to permit a reasoned choice. The key issue is whether the selection and discussion of alternatives fosters informed decision making and meaningful public participation. A CEQA document need not consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative. SCAQMD Rule 110 (the rule which implements the SCAQMD's certified regulatory program) does not impose any greater requirements for a discussion of project alternatives in an environmental assessment than is required for an EIR under CEQA.

PROJECT OBJECTIVES

As noted in Chapter 2, CEQA Guidelines §15124(b) requires the project description to include a statement of objectives sought by the proposed project, including the underlying purpose of the proposed project. Compatibility with project objectives is one criterion for selecting a range of reasonable project alternatives and provides a standard against which to measure project alternatives. The project objectives identified in the following bullet points have been developed: 1) in compliance with CEQA Guidelines §15124 (b); and, 2) to be consistent with policy objectives of the SCAQMD's desire to implement AQMP, yet allow feasible compliance dates. The project objectives are as follows:

- to maintain the lower limits on NOx, VOC, and CO emissions from the combustion of gaseous and liquid biogas engines;
- place biogas engines on a more suitable compliance schedule with achievable emission limitations due to the fact that retrofit construction schedules may reach completion beyond the current compliance deadline and demonstration project control technologies have not matured in a timely manner for these types of engines;
- to comply with EPA Breakdown provision requirements; and
- aside from temporary air quality impacts, avoid generating any new adverse environmental impacts.

ALTERNATIVES REJECTED AS INFEASIBLE

A CEQA document should identify any alternatives that were considered by the lead agency, but were rejected as infeasible during the scoping process and explain the reasons underlying the lead agency's determination (CEQA Guidelines §15126.6(c)). While the scope and goals of proposed projects may be relatively specific, a variety of options can be considered as alternatives to the proposed project. The following alternatives have been eliminated from further detailed consideration in the EA for the following reasons: 1) they fail to meet the most basic project objectives, 2) they are infeasible as defined by CEQA (CEQA Guidelines §15364), or 3) they are unable to avoid significant impacts (CEQA Guidelines §15126.6(c)).

Trucking Gas Offsite

This potential alternative would require affected facilities that cannot meet the delayed compliance timeline of the proposed project to truck their biogas offsite. However, trucking the gas offsite would be technically challenging and have safety issues. The biogas would need to be cleaned before use and be trucked off to a facility that would be able to process the gas. There would be additional air quality impacts due to the trucks' emissions and processing of the gas. Also the facilities would lose the benefit of using their gas for electric generation. While this potential alternative would reduce NOx, VOC and CO emissions from the combustion of gaseous and liquid fuels from their engines, thus generating an air quality benefit, this alternative has been eliminated from consideration because it does not meet the fourth basic project objective: to avoid any new adverse environmental impacts. Based on these reasons, this alternative will not be further considered.

Compress for Gas Sales and Pipeline

This potential alternative would require affected facilities that cannot meet the delayed compliance timeline of the proposed project to compress their biogas for sale and send the biogas to a pipeline. There are several issues on why this is infeasible: safety, legality, land availability, consistent gas, and proximity of a pipeline. Under this alternative, the gas would be sold to a local biogas provider rather than being used with onsite with biogas engines. In addition, a gas processing plant (Gas Plant) would be required to meet the provider's specifications. The Gas Plant may be comprised of initial compression of field gas (i.e. compressor, scrubbers), dehydration (i.e. separators, scrubbers, condensers, stabilization units, heat exchangers, chillers, glycol separators and filters, glycol pumps, glycol regenerator/reboiler, compressors, other refrigeration equipment items, natural gas liquid (NGL) vessel/tanks), potential CO_2 removal in an amine unit (gas and liquid separators, amine contactor, amine filter, amine vessel/tank, heat exchanger and reboiler, cooler, pumps, etc.), and flares and/or permitted microturbines to combust tail gas from the gas sales equipment. In addition to the Gas Plant, gas metering and odorizing equipment would be required by the local gas provider and the US DOT. Also the facilities would lose the benefit of using their gas for electric generation. While this potential alternative would reduce NOx, VOC and CO emissions from the combustion of gaseous and liquid fuels from their engines, thus generating an air quality benefit, this alternative has been eliminated from consideration because, as mentioned above, it is not technology feasible due to safety, legality, land availability, consistent gas, and proximity of a pipeline. Additionally, by operators using their biogas engines to generate their electricity, they are part of the State's renewable energy portfolio. Lastly, this alternative does not meet the fourth basic project objective: to avoid any adverse environmental impacts. Based on these reasons, this alternative will not be further considered.

ALTERNATIVES SUMMARY

The proposed project and four alternatives to the proposed project are summarized in Table 5-1: Alternative A (No Project), Alternative B (Additional Delayed Compliance), Alternative C (Replace Flare) and Alternative D (New Micro Turbines). Pursuant to CEQA Guidelines §15126.6 (b), the purpose of an alternatives analysis is to reduce or avoid potentially significant adverse effects that a project may have on the environment. The environmental topic area identified in the NOP/IS that may be adversely affected by the proposed project was air quality and greenhouse gases impacts. A comprehensive analysis of potential air quality impacts is included in Chapter 4 of this document. This chapter provides a comparison of the potential air quality impacts from each of the project alternatives relative to the proposed project, which are summarized in Table 5-2. That analysis concluded that only air quality impacts have the potential to be significant. Aside from air quality, no other significant adverse impacts were identified for the proposed project and the following analyzes the project alternatives. As indicated in the following discussions, the proposed project is considered to provide the best balance between meeting the objectives of the project while minimizing potentially significant adverse environmental impacts.

Table 5-1
Summary of PAR 1110.2 and Project Alternatives

Project	Project Description
Alternative A (No Project)	The proposed project would not be adopted and the current universe of equipment will continue to be subject to the NOx, VOC and CO emission limits according to the current compliance schedule in Rule 1110.2. If facilities cannot comply with the existing rule, operators may shut down their biogas engines and release their gas through their existing flares and purchase electricity. Additionally, if potential gross emission violations during preventable breakdowns occur, corrective actions may not ensue. By not resolving this issue, this will result in EPA not approving the 2010 amendment into the State Implementation Plan (SIP). If this disapproval is finalized, sanctions would be imposed unless the U.S. EPA approves subsequent SIP revisions that correct the rule deficiencies within 18 months of disapproval.
Alternative B (Additional Delayed Compliance)	Provides additional delay of NOx, CO, and VOC emission limits compliance requirements for affected facilities beyond the proposed project. All other requirements and conditions in the proposed project would be applicable.
Alternative C (Replace Flares)	Through additional rule making, the facilities not meeting the current Rule 1110.2 biogas emission limits would be required to process the biogas through new cleaner and efficient flares (ultra-low NOx Bekaert Clean Enclosed Burner®; Bekaert CEB®) under a separate rule. The new flares' emission limits would be comparable to the NOx, CO, and VOC emission limits of the proposed project. GHG emissions would increase from power plants needed to generate electricity that would otherwise be generated from the biogas engines and backup diesel engines. All other requirements and conditions in the proposed project would be applicable.
Alternative D (New Micro Turbines)	Through additional rule making, the facilities not meeting the current Rule 1110.2 biogas emission limits would be required to process the biogas through new micro turbines (Capstone C65) to handle their facilities' biogas under a separate rule. The new microturbines' emission limits would be comparable to the NOx, CO, and VOC emission limits of the proposed project. GHG emissions would increase from backup diesel engines. All other requirements and conditions in the proposed project would be applicable.

Table 5-2

Comparison of Adverse Environmental Impacts of the Alternatives

Category	Proposed Project	Alternative A: No Project	Alternative B: Additional Delayed Compliance	Alternative C: Replace Flares	Alternative D: New Micro Turbines
Air Quality Impacts: Construction	This proposed amendment does not have any construction impacts. Construction impacts were analyzed for the 2007 PAR 1110.2 EA.	No construction impacts.	Same as proposed project.	Same as proposed project.	Same as proposed project.
Significant?	No	No	No	No	No
Air Quality Impacts: Operation	Approximately 0.9 tons of NOx, 0.5 tons/day of VOC, and 20 tons/day of CO peak daily emission reductions delayed; increases emission reductions from air quality improvement projects funded by compliance flexibility fee in Rule 1110.2.	Fewer emissions than proposed project due to no delay in emission reductions from proposed project; similar anticipated emission reductions from air quality improvement projects funded by compliance flexibility fee in Rule 1110.2.	More delayed emission reductions than proposed project due to additional compliance delay; potentially less emission reductions from air quality improvement projects funded by compliance flexibility fee in Rule 1110.2.	Due to the new flares being more efficient in combustion than the biogas engines, there would be less NOx, VOC and CO emissions than the proposed project. There would be additional emissions from power plants and backup engines. Thus, these emissions would still exceed the SCAQMD CEQA significance thresholds for operation.	Due to the new microturbines being more efficient in combustion than the biogas engines, there would be less NOx and CO emissions than the proposed project. There would be an increase in VOC emissions compared to the proposed project. There would be additional emissions from backup engines. Thus, these emissions would still exceed the SCAQMD CEQA significance thresholds for operation.
Significant?	Yes	No	Yes	Yes	Yes

Category	Proposed Project	Alternative A: No Project	Alternative B: Additional Delayed Compliance	Alternative C: Replace Flares	Alternative D: New Micro Turbines
Air Quality Impacts: GHG	None. Control equipment only controls NOx, VOC, and CO emissions.	Same as proposed project	Same as proposed project	GHG emissions would increase from power plants and back up diesel engines. However the emissions are less than the SCAQMD CEQA significance threshold for GHG.	GHG emissions would increase from back up diesel engines. However, the emissions are less than the SCAQMD CEQA significance threshold for GHG.
Significant?	No	No	No	No	No

DESCRIPTION OF PROJECT ALTERNATIVES

The project alternatives described in the following subsections were developed by modifying specific components of the proposed project. The rationale for selecting and modifying specific components of the proposed project to generate feasible alternatives for the analysis is based on CEQA's requirement to present "realistic" and “potentially feasible” alternatives: that is, alternatives that can actually be implemented. When considering approval of the proposed project, the SCAQMD’s Governing Board may choose all of or portions of any of the alternatives analyzed, as well as variations on the alternatives, since the comparative merits of the project alternatives have been analyzed and circulated for public review and comment along with the analysis of the proposed project. The main components of the proposed project and each project alternative are summarized in Table 5-3. A complete description of the proposed project can be found in Chapter 2 (Project Description) and any element of the proposed project not listed will remain the same for Alternatives B and C.

Table 5-3
Comparison of Key Components of the Proposed Project to the Alternatives

Proposed Project (Key Components)	**Alternative A:** No Project	**Alternative B:** Additional Delayed Compliance	**Alternative C:** Replace Flares	**Alternative D:** New Micro Turbines
Delays compliance with lower NOx, VOC, and CO emission limits for at least one additional year beyond the date currently set in Rule 1110.2	No change in current NOx, VOC, and CO emission reductions pursuant to Rule 1110.2	Additional delays of one additional year in NOx, VOC, and CO emission reductions would occur beyond the proposed project	Additional delay in NOx, VOC, and CO emissions reductions would occur than proposed project due to the time challenges in rulemaking, engineering, permitting, and installation	Additional delay in NOx, VOC, and CO emissions reductions would occur than proposed project due to the time challenges in rulemaking, engineering, permitting, and installation
NOx emission limits of 11 ppmvd, VOC limit of 30 ppmvd and CO limit of 250 ppm	Rule 1110.2 emission limits would apply (eg.- 11 ppmvd NOx, 30 ppmvd VOC, and 250 ppmvd limit for biogas engines)	Same as proposed project	Same as proposed project under a different rule making	Same as proposed project under a different rule making
Includes options for alternate compliance flexibility fee option to delay compliance	Rule 1110.2 alternate compliance flexibility fee option would still be applicable	Same as proposed project	Would be considered under a different rule making	Would be considered under a different rule making
EPA Breakdown Provisions	Sanctions would be imposed unless the U.S. EPA approves subsequent SIP revisions that correct the rule deficiencies within 18 months of disapproval.	Same as proposed project	Equivalent to proposed project, but would be considered under a different rule making	Equivalent to proposed project, but would be considered under a different rule making

<u>Alternative A - No Project</u>

CEQA Guidelines §15126.6 requires evaluation of a no project alternative to allow decision makers to compare the impacts of approving the proposed project with the impacts of not approving the proposed project. The No Project Alternative assumes that the proposed project or Alternatives B, C or D would not be adopted.

Alternative A or ‘no project’ means that the current universe of affected equipment (e.g., biogas) will continue to be subject to the NOx, CO, and VOC emission limits according to the current compliance schedule in Rule 1110.2. By not delaying the compliance schedule for biogas engines, operators will continue to experience compliance challenges. The no project alternative is technically not feasible. Thus, under Alternative A, owners/operators of equipment not able to meet the applicable NOx, VOC, and CO emission limits by the applicable compliance date will need to shut down the equipment and use their existing flares to flare their biogas or apply for a variance to comply. By flaring the biogas, the operators will lose the benefit of harnessing the available energy. Additionally, there would be GHG emissions from power plants needed to generate electricity that would otherwise be generated from the biogas engines and backup diesel engines. (See the 2012 Addendum to the 2007 Final EA for details)

Table 5-4
Comparison of Emissions with Alternative A

Alternative:	**NOx (tpd)**	**VOC (tpd)**	**CO (tpd)**	**CO2e (MT/yr)**
Existing Setting	1.3	0.8	25.6	307,696
Full Compliance with Rule Limits	0.44	0.33	5.66	307,696
Alternative A (on-site)	0.36	0.22	0.76	308,003
Alternative A (on-site and off-site)	0.36	0.24	0.97	308,119

*On-site emissions include backup diesel engines, and off-site emissions include electricity generation.

<u>Alternative B – Additional Delayed Compliance</u>

Alternative B is the additional delayed compliance alternative because it would provide an additional delay in the compliance schedule beyond what is proposed in PAR 1110.2, for meeting the NOx, VOC, and CO emission limits from affected sources. The proposed rule sets more than one deadline to comply with lower NOx, VOC, and CO emissions limits for demonstration projects and all other biogas engines. Alternative B would provide an additional one year delay beyond the dates with the proposed rule. The extra time would further assist the development of new technology and ensure affected sources would comply with the lower NOx, VOC, and CO limits. Alternative B would also include an alternate compliance flexibility mitigation fee option, which is currently included in Rule 1110.2. However, with the additional time to comply with the lower limits, it is likely less affected sources will take advantage of alternative compliance flexibility fee option. The amount of NOx, VOC, and CO emission reductions to be delayed overall would exceed the air quality significance threshold for NOx, VOC, and CO during operation and thus, would create significant adverse air quality impacts during operation.

<u>Alternative C – Replace Flares</u>

Alternative C is a potential alternative that would require affected facilities that cannot meet the delayed compliance timeline of the proposed project to upgrade their existing flares to new flares through separate rulemaking. These facilities would be required to process the biogas through cleaner flares. As discussed in Chapter 4, GHG impacts would be the same as the fuel usage does not change; however, there would be an increase in GHG from the power plants and backup diesel engines. Under Alternative C, the amount of GHG emissions would increase from electricity generation (power plants and backup diesel engines), but direct NOx, VOC and CO emissions will decrease (see Table 5-5) as compared to the proposed project, while indirect NOx, VOC, and CO emissions would increase from the power plants and backup diesel engines. Construction emissions would be similar to the proposed project. Furthermore, there would be additional delays because by the time it would take to develop a new rule, engineer, permit, and install, it would be more years than the proposed project. Even though Alternative C, does not achieve the goals of the proposed project, it is the environmentally superior alternative in accordance with CEQA Guidelines §15126.6(e)(2) because it will result in the lowest level of NOx, VOC, and CO emissions thus, improving the air quality in the District. See Appendix B of this ~~draft~~Final SEA for calculations.

Table 5-5
Comparison of Emissions with Alternative C

Alternative:	NOx (tpd)	VOC (tpd)	CO (tpd)	CO2e (MT/yr)
Existing Setting	1.3	0.8	25.6	307,696
Full Compliance with Rule Limits	0.44	0.33	5.66	307,696
Alternative C (on-site)*	0.18	0.04	0.12	308,003
Alternative C (on-site and off-site)*	0.18	0.06	0.34	308,119

*On-site emissions include backup diesel engines, and off-site emissions include electricity generation.

<u>Alternative D – New Micro Turbines</u>

Alternative D is a potential alternative that would require affected facilities that cannot meet the delayed compliance timeline of the proposed project to replace their existing engines to new microturbines through separate rulemaking. These facilities would be required to process the biogas through microturbines. Construction emissions would be similar to the proposed project. As discussed in Chapter 4, GHG impacts would be the same as the fuel usage does not change; however, there would be an increase in GHG emissions from the backup diesel engines. Under Alternative D, the amount of NOx and CO emissions would decrease while the VOC and GHG emissions will increase relative to the proposed project (see Table 5-6). See Appendix B of this ~~draft~~Final SEA for calculations.

Table 5-6
Comparison of Emissions for Proposed Project and Alternative D

Alternative:	NOx (tpd)	VOC (tpd)	CO (tpd)	CO2e (MT/yr)
Existing Setting	1.3	0.8	25.6	307,696
Proposed Project Future Emissions	0.44	0.33	5.66	307,696
Alternative D (on-site)	0.35	0.66	4.21	308,003

* Off-site emissions include backup diesel engines.

COMPARISON OF ALTERNATIVES

The Environmental Checklist (see Chapter 2 of the Initial Study in Appendix B) identified only air quality and greenhouse gas emissions during operations as the environmental area that could be significantly adversely affected by the proposed project. The following section describes the potential adverse operational air quality impacts that may be generated by each project alternative compared to the proposed project. A summary of the adverse operational air quality impacts for the proposed project and each project alternative are also provided in Table 5-2. No other environmental topics other than operational air quality were determined to be potentially significantly adversely affected by implementing any project alternative.

Alternative A - No Project

Unlike the proposed project, it is not anticipated that Alternative A would generate significant adverse impacts during operation because the owners/operators of affected equipment would be expected to comply with the applicable NOx, VOC, and CO limits in accordance with the current compliance schedule for existing (in-use) equipment in Rule 1110.2. Instead, owners/operators of the affected equipment would continue existing operations in compliance with the current NOx, VOC, and CO limits and non-compliant equipment would need to be shutdown. By not adopting the proposed project, current operations mean that each owner/operator of affected equipment would not be able to delay the compliance schedule (e.g., retrofitting existing equipment by installing control equipment). Thus, under Alternative A, owners/operators of equipment not able to meet the applicable NOx, VOC, and CO emission limits by the applicable compliance date will need to shut down the equipment and use their existing flares to flare their biogas or apply for a variance to comply. By flaring the biogas, the operators will lose the benefit of harnessing the available energy. Additionally, there would be GHG emissions from power plants needed to generate electricity that would otherwise be generated from the biogas engines and backup diesel engines. (See 2012 Addendum to the 2007 Final EA for details)

Alternative A will achieve the emission reduction goals of Rule 1110.2; however, it does not achieve all of the goals of the proposed project because it does not acknowledge that for some affected equipment, the current emission limits of Rule 1110.2 are not yet demonstrated for newer demonstration project technologies.

Alternative B – Additional Delayed Compliance

Because Alternative B would provide an additional delay in the compliance schedule beyond the proposed project, it would result in additional delayed emission reductions, thus would create additional significant adverse air quality impacts during the additional year of delayed compliance. With less affected sources likely to need the alternative compliance options, emission reductions from the compliance flexibility fee option would be less than anticipated under the proposed project. Stakeholders have also voiced concern about needing more time. If Alternative B were implemented, fewer reductions in emissions would be achieved and less corresponding health benefits from reducing overall emissions will be realized between compliance years 2017 and 2019. Alternative B does not minimize the delay in emission reductions as compared to the proposed project.

Alternative C – Replace Flares

Alternative C proposes the same emission limits as the proposed project, but instead of using their biogas engines, the facilities would need to replace their existing flares with new efficient flares. This would be required under a separate rule making. The Flares' NOx, CO, and VOC emissions would be lower than the proposed project. If Alternative C were implemented, GHG emissions will increase from electricity generation (power plants and backup diesel engines), but less NOx, VOC and CO emissions would be emitted when compared to the proposed project (see Table 5-4 for comparison). However, the increase in GHG emissions is less than the SCAQMD CEQA significance threshold for GHG.

<u>Alternative D – New Micro Turbines</u>

Alternative D proposes the same emission limits as the proposed project. Instead of using biogas engines, the facilities would need to install new micro turbines to meet the emissions reductions. This would be required under a separate rule making. If Alternative D were implemented, potentially less NOx and CO emissions would be emitted when compared to the proposed project, but there would be an increase in VOC and GHG emissions (see Table 5-6 for comparison). However, the increase in GHG emissions is less than the SCAQMD CEQA significance threshold for GHG. There also would be potential issues with noise, aesthetics, and availability of land for operators.

LOWEST TOXIC AND ENVIRONMENTALLY SUPERIOR ALTERNATIVES

In accordance with SCAQMD's policy document Environmental Justice Program Enhancements for FY 2002-03, Enhancement II-1 recommends that all SCAQMD CEQA assessments include a feasible project alternative with the lowest air toxics emissions. In other words, for any major equipment or process type under the scope of the proposed project that creates a significant environmental impact, at least one alternative, where feasible, shall be considered from a "least harmful" perspective with regard to hazardous air emissions.

Implementing Alternative C has the lowest impacts in emissions and the best corresponding health benefits when compared to the proposed project, Alternatives A, B or D. Thus, Alternative C is considered to be the environmentally superior alternative. However, Alternative C would not fulfill one of the four objectives of the proposed project as listed earlier in this chapter. Alternative C would not place biogas on a more suitable compliance schedule with achievable emission limitations due to the fact that control technologies have not matured in a timely manner for this particular category of equipment. Therefore, the proposed project is the most superior.

CONCLUSION

By not adopting the proposed project, Alternative A would not delay the operational subject emission reductions and will achieve the same emission reductions currently required under Rule 1110.2. However, Alternative A would not achieve one of the project objectives for the proposed project because Alternative A will not place the biogas engines on a more suitable compliance schedule with achievable emission limitations due to the fact that retrofit construction schedules may reach completion beyond the current compliance deadline and the demonstration project control technologies have not matured in a timely manner for this particular category of equipment.

If Alternative B were implemented, less NOx, VOC, and CO emissions reductions would be achieved since the biogas engines would have an extra year to emit at the higher emissions rate and overall less health benefits from reducing emissions overall will be achieved. Alternative B provides fewer benefits to air quality and public health compared to the proposed project. Of the adverse environmental impacts that would be generated under Alternative B, the impacts would be initially more than the proposed project and significant for air quality.

If Alternative C were implemented, the energy benefit from harnessing the biogas would be lost. Although the NO_X, VOC, and CO emissions would be reduced, more GHG emissions would be emitted when compared to the proposed project and would not meet any of the project's objectives.

If Alternative D were implemented, there would be an energy benefit and there would be less NOx and CO emissions as compared to the proposed project. However, there would be an increase in

VOC and GHG emissions. There might also be potential noise and aesthetics impacts as compared to the proposed project. Alternative D would not meet all of the project's objectives.

Thus, when comparing the environmental effects of the project alternatives with the proposed project and evaluating the effectiveness of achieving the project objectives of the proposed project versus the project alternatives, the proposed project provides the best balance in achieving the project objectives while minimizing the adverse environmental impacts to air quality.

APPENDICES

APPENDIX A

PROPOSED AMENDED RULE 1110.2

In order to save space and avoid repetition, please refer to the latest version of Proposed Amended Rule 1110.2 located in the December 4, 2015 Governing Board Package. The version of Proposed Amended Rule 1110.2 that was circulated with the Draft SEA released on September 1, 2015 for a 45-day public review and comment period ending October 16, 2015 was "PAR 1110.2 August 28, 2015".

Original hard copies of the Draft SEA, which include the draft version of the proposed rule listed above, can be obtained through the SCAQMD Public Information Center at the Diamond Bar headquarters or by calling (909) 396-2039.

APPENDIX B

ASSUMPTIONS AND CALCULATIONS

Biogas Fuels

CO2 EF	0.0750332	lb/scf	CH4 EF	4.62E-06	lb/scf	N2O EF	9.10514E-06	lb/scf
	75,033.20	lb/MMscf		4.620913	lb/MMscf		9.105139002	lb/MMscf
CO2	1,788,389.06	lb/day	CH4	110.14	lb/day	N2O	217.02	lb/day
	296,171.51	MT/yr		18.24	MT/yr		35.94	MT/yr

Other Biomass Gases

CO2 Factor	CH4 Factor	N20 Factor
kg per scf	g per scf	g per scf
0.034106	0.002096	0.00413

http://www.epa.gov/climateleadership/documents/emission-factors.pdf

Flares Operational Emissions

CEB Max Gas Capacity	39,460,000	BTU/hr
Avg of Landfill & Digester HHV[1]	738	BTU/scf

[1] Source C65 MT

Landfill and Digester Fuel Usage	23.83	MMscf/day

Project Operating Conditions

Total # of CEBs	19	
Fuel Usage Per CEB	1.3	MMscf/day
	39.460	MMBtu/hr

Project: CEBs Criteria Pollutant Emissions

Pollutant	Emission Factors[1]		Emissions Per CEB[2]		Emissions for All CEBs		
			(lbs/day)	(lbs/yr)	(lbs/day)	(lbs/yr)	(tpd)
VOC	0.0042	lb/MMBtu	4.0	1,452	73.9	26,965	0.04
NO_x	0.018	lb/MMBtu	17.0	6,222	316.6	115,566	0.16
CO	0.0074	lb/MMBtu	7.0	2,558	130.2	47,510	0.07

[1] VOC, NO_x and CO emissions factors were obtained from manufacturer specifications. The PM emission factor is from AP-42 Table 13.5-1, note C (Industrial flares).

[2] Emissions are calculated using 737 Btu/scf as the heating value

Project: CEBs GHG Emissions

Pollutant	Emission Factors[1] (lb/MMscf)	Emissions Per CEB (MT/yr)	Total Emissions for All CEBs (MT/yr)	Global Warming Potentials[2]	CO_2e Emissions Per CEB (MT/yr)	CO_2e Emissions for All CEBs (MT/yr)
CH_4	4.6	0.98	18.24	21	20.62	383.03
N_2O	9.11	1.93	35.94	310	599.85	11,141.36
CO_2	75,033	15,946	296,172	1	15,946	296,172
				Total CO_2e Emissions:	16,566	307,696

[1] EPA's Emissions Factors for GHG Inventories 2011

[2] Global warming potentials are from Table 1 of SCAQMD Rule 2700.

Microturbine Emissions

MT Heat Input Capacity	872,000	BTU/hr
Landfill & Digester HHV	738	BTU/scf
Landfill and Digester Gas Fuel Usage	24	MMscf/day
	23834637	scf/day

Cumulatives: Addition of Microturbines

Total # of Microturbines	840	
Rating of each Microturbine	65	kW
Fuel Usage per Microturbine	28,358	scf/day
	0.028	

Cumulatives: Microturbines Criteria Pollutant Emissions

Pollutant	Emission Factors			Emissions Microturbines		
				(lbs/day)	(lbs/yr)	(tpd)
VOC	1.0	lb/MW-hr		1311.2	478,580	0.66
NO_x	0.5	lb/MW-hr		655.6	239,290	0.33
CO	6.0	lb/MW-hr		7867	2,871,481	3.93

1. VOC, NO_x and CO emissions factors are from the CARB Certification for Capstone C65 Microturbines (Executive Order DG-030-A).

Cumulatives: Microturbines GHG Emissions

Pollutant	Emission Factors[1] (lbs/MMscf)	Emissions (MT/yr)	All MT Emisions	Global Warming Potentials[2]	CO_2e Emissions (MT/yr)
CH_4	4.6	0.022	18.240	21	383.0
N_2O	9.1	0.043	35.940	310	11141.4
CO_2	75,033	352	296,171.510	1	296171.5
				Total CO_2e Emissions:	**307,696**

1. Emission factors for GHG Inventories, EPA

2. Global warming potentials are from Table 1 of SCAQMD Rule 2700.

APPENDIX C

NOTICE OF PREPARATION OF A DRAFT SUBSEQUENT ENVIRONMENTALASSESSMENT FOR PROPOSED AMENDED RULE 1110.2 – EMISSIONS FROM GASEOUS-AND LIQUID-FUELED ENGINES

South Coast
Air Quality Management District

21865 Copley Drive, Diamond Bar, CA 91765-4182
(909) 396-2000 • www.aqmd.gov

SUBJECT: **NOTICE OF PREPARATION OF A DRAFT SUBSEQUENT ENVIRONMENTAL ASSESSMENT**

PROJECT TITLE: **PROPOSED AMENDED RULE 1110.2 – EMISSIONS FROM GASEOUS-AND LIQUID-FUELED ENGINES**

In accordance with the California Environmental Quality Act (CEQA), the South Coast Air Quality Management District (SCAQMD), as the Lead Agency, has prepared this Notice of Preparation (NOP) and Initial Study (IS). This NOP serves two purposes: 1) to solicit information on the scope of the environmental analysis for the proposed project, and 2) to notify the public that the SCAQMD will prepare a Draft Subsequent Environmental Assessment (SEA) to further assess potential environmental impacts that may result from implementing the proposed project.

This letter, NOP and the attached IS are not SCAQMD applications or forms requiring a response from you. Their purpose is simply to provide information to you on the above project. If the proposed project has no bearing on you or your organization, no action on your part is necessary.

The IS and other relevant documents may be obtained by calling the SCAQMD Public Information Center at (909) 396-2039 or accessing the SCAQMD's CEQA website at. http://www.aqmd.gov/home/about/public-notices/ceqa-notices/notices-of-preparation. Comments focusing on issues relative to the environmental analysis should be addressed to Ms. Cynthia Carter (c/o CEQA) at the address shown above, or sent by FAX to (909) 396-3324 or by e-mail to ccarter@aqmd.gov. Comments must be received no later than 5:00 PM on Thursday, August 27, 2015. Please include the name and phone number of the contact person. Questions regarding the proposed amendments should be directed to Mr. Kevin Orellana at (909) 396-3492 or by email to korellana@aqmd.gov.

The Public Hearing for the proposed amended regulation is scheduled for November 6, 2015 at the SCAQMD Headquarters in Diamond Bar, California. (Note: Public meeting dates are subject to change).

Date: July 28, 2015

Signature: Jillian Wong

Jillian Wong, Ph.D.
Program Supervisor, CEQA
Planning, Rules, and Area Sources

Telephone: (909) 396-3176

Reference: California Code of Regulations, Title 14, Sections 15082(a), 15103, and 15375

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
21865 Copley Drive, Diamond Bar, CA 91765-4182

NOTICE OF PREPARATION OF A DRAFT SUBSEQUENT ENVIRONMENTAL ASSESSMENT

Project Title:
Initial Study for Proposed Amended Rule (PAR) 1110.2 - Emissions from Gaseous- and Liquid-Fueled Engines

Project Location:
South Coast Air Quality Management District (SCAQMD) area of jurisdiction consisting of the four-county South Coast Air Basin (Orange County and the non-desert portions of Los Angeles, Riverside and San Bernardino counties), and the Riverside County portions of the Salton Sea Air Basin and the Mojave Desert Air Basin

Description of Nature, Purpose, and Beneficiaries of Project:
The proposed project affects all stationary and portable engines over 50 rated brake horsepower within the SCAQMD jurisdiction. Rule 1110.2 limits NOx, VOC, and CO emissions from the combustion of gaseous- and liquid-fueled engines. Under PAR 1110.2, biogas-fired engines would have additional time to comply with the rule's emission limits. Additionally, limits will be placed on the number of breakdowns and emissions during breakdown events for all engines. Other minor changes are proposed for clarity and consistency throughout the rule. The Initial Study identifies the following environmental topic area that may be adversely affected by the proposed project: air quality and greenhouse gas emissions. Impacts to this environmental area will be further analyzed in the Draft Subsequent Environmental Assessment.

Lead Agency:	**Division:**
South Coast Air Quality Management District	Planning, Rule Development and Area Sources

The Initial Study and all supporting documentation are available at:	**or by calling:**	**The Initial Study can also be obtained by accessing the SCAQMD's website at:**
SCAQMD Headquarters 21865 Copley Drive Diamond Bar, CA 91765	(909) 396-2039	http://www.aqmd.gov/home/about/public-notices/ceqa-notices/notices-of-preparation

The Initial Study is provided to the public through the following:
☑ Los Angeles Times (July 29, 2015) ☑ SCAQMD Website ☑ SCAQMD Mailing List

Initial Study Review Period (30-day):
July 29, 2015–August 27, 2015

The proposed project may have statewide, regional or areawide significance; therefore, a CEQA scoping meeting is required (pursuant to Public Resources Code §21083.9(a)(2)) and will be held on August 13, 2015. See Scheduled Public Meeting Dates below for details.

Scheduled Public Meeting Dates (subject to change):
CEQA Scoping Meeting: August 13, 2015 at 10:00 am; in Conference Room GB at SCAQMD Headquarters
SCAQMD Governing Board Hearing: November 6, 2015, 9:00 a.m.; SCAQMD Headquarters

Send CEQA Comments to:	**Phone:**	**Email:**	**Fax:**
Ms. Cynthia Carter	(909) 396-2431	ccarter@aqmd.gov	(909) 396-3324

Direct Questions on Proposed Amended Rule:	**Phone:**	**Email:**	**Fax:**
Mr. Kevin Orellana	(909) 396-3492	korellana@aqmd.gov	(909) 396-3324

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Initial Study for:

Proposed Amended Rule 1110.2 - Emissions From Gaseous-and Liquid-Fueled Engines

July 2015

SCAQMD No. 150728CC

Executive Officer
Barry R. Wallerstein, D. Env.

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 and Rules Manager
Planning, Rule Development and Area Sources
Ian MacMillan

Author:	Cynthia A. Carter	Air Quality Specialist
Technical Assistance:	Kevin Orellana	Air Quality Specialist
Reviewed By:	Jillian Wong, Ph.D.	CEQA Program Supervisor
	William Wong	Principal Deputy District Counsel
	Gary Quinn, P.E.	Program Supervisor

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
GOVERNING BOARD

TABLE OF CONTENTS

List of Tables

List of Figures

CHAPTER 1 – PROJECT DESCRIPTION

INTRODUCTION

The California Legislature created the South Coast Air Quality Management District (SCAQMD) in 1977[1] as the agency responsible for developing and enforcing air pollution control rules and regulations in the South Coast Air Basin (Basin) and portions of the Salton Sea Air Basin and Mojave Desert Air Basin referred to herein as the district. By statute, the SCAQMD is required to adopt an air quality management plan (AQMP) demonstrating compliance with all federal and state ambient air quality standards for the district[2]. Furthermore, the SCAQMD must adopt rules and regulations that carry out the AQMP[3]. The 2007 AQMP concluded that major reductions in emissions of volatile organic compounds (VOCs), oxides of sulfur (SOx) and oxides of nitrogen (NOx) are necessary to attain the air quality standards for ozone (the key ingredient of smog) and particulate matter (PM10 and PM2.5). Ozone, a criteria pollutant, is formed when VOCs react with NOx in the atmosphere and has been shown to adversely affect human health and to contribute to the formation of PM10 and PM2.5.

- Rule 1110.2 was adopted in August 1990 to control NOx, carbon monoxide (CO), and VOC from gaseous and liquid-fueled internal combustion engines (ICEs). For all stationary and portable engines over 50 brake horsepower (bhp), it required that either 1) NOx emissions be reduced over 90 percent to one of two compliance limits specified by the rule, or; 2) the engines be permanently removed from service or replaced with electric motors.
- It was amended in September 1990 to clarify rule language.
- It was then amended in August and December of 1994 to modify the CO monitoring requirements and to clarify rule language.
- The amendment of November 1997 eliminated the requirement for continuous monitoring of CO, reduced the source testing requirement from once every year to once every three years, and exempted non-road engines, including portable engines, from most requirements.
- The June 2005 amendment made the previously exempt agricultural engines subject to the rule.
- The February 2008 amendment limited NOx, VOC and CO emissions from gaseous and liquid-fueled biogas ICE to partially implement the 2007 AQMP Control Measure MCS-01 – Facility Modernization, which requires facilities to retrofit or replace their equipment to achieve Best Available Control Technology (BACT) emission levels. The 2008 amendments affected stationary, non-emergency engines and increased monitoring requirements; required to meet emission standards equivalent to BACT; required new electrical generating engines to meet the same requirements as large central power plants, and clarified portable engine requirements. It also removed obsolete portable engine requirements from the rule.
- In 2010, the rule was amended to add an exemption affecting a remote public safety communications site.
- In September 2012, because of biogas technology demonstration issues, the 2008 amendment requirements were delayed.

---

[1] The Lewis-Presley Air Quality Management Act, 1976 Cal. Stats., ch 324 (codified at Health & Safety Code, §§40400-40540).
[2] Health & Safety Code, §40460 (a).
[3] Health & Safety Code, §40440 (a).

Proposed Amended Rule (PAR) 1110.2 will result in a delay of: 0.9 tons/day of NOx, 0.5 tons/day of VOC, and 20 tons/day of CO emission reductions. However, these delayed emission reductions will be recaptured in compliance years 2017 and 2018, respectively. Based on EPA direction for Rule 1110.2 SIP approval, the proposed amended rule (PAR) 1110.2 will place limits on the number of breakdowns and emissions during breakdown events. SCAQMD staff's recent evaluation of the state of compliance with Rule 1110.2 as well as feedback from industry revealed that some equipment owners/operators are experiencing compliance challenges, in particular, with certain effective dates in the rule. To address these compliance challenges and ensure that equipment owners/operators are not unnecessarily burdened with additional costs, SCAQMD staff is proposing to amend Rule 1110.2 to delay implementation of NOx, VOC, and CO emission limits compliance dates for biogas engines.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

The proposed amendments to Rule 1110.2 are considered a "project" as defined by CEQA. CEQA requires that the potential adverse environmental impacts of proposed projects be evaluated and that methods to reduce or avoid identified significant adverse environmental impacts of these projects be implemented if feasible. The purpose of the CEQA process is to inform the SCAQMD's Governing Board, public agencies, and interested parties of potential adverse environmental impacts that could result from implementing the proposed project and to identify feasible mitigation measures or alternatives, when an impact is significant.

California Public Resources Code §21080.5 allows public agencies with regulatory programs to prepare a plan or other written documents in lieu of an environmental impact report once the Secretary of the Resources Agency has certified the regulatory program. The SCAQMD's regulatory program was certified by the Secretary of Resources Agency on March 1, 1989, and is codified as SCAQMD Rule 110. Pursuant to Rule 110 (the rule which implements the SCAQMD's certified regulatory program), SCAQMD is preparing a Draft Environmental Assessment (EA) to evaluate potential adverse impacts from the proposed project.

The SCAQMD, as Lead Agency for the proposed project, has prepared this Initial Study (which includes an Environmental Checklist and project description). The Environmental Checklist provides a standard evaluation tool to identify a project's adverse environmental impacts. The Initial Study is also intended to provide information about the proposed project to other public agencies and interested parties prior to the release of the Draft SEA. Written comments on the scope of the environmental analysis will be considered (if received by the SCAQMD during the 30-day review period) when preparing the Draft SEA.

A Subsequent EA is the appropriate CEQA document for the proposed project because there are subsequent changes proposed to Rule 1110.2 (CEQA Guidelines §15162). The proposed project is a modification of an earlier project (December 2007 Final EA, Certified on February 1, 2008) and this analysis considers only the incremental effects of the proposed project.

PROJECT LOCATION

PAR 1110.2 would apply to all stationary and portable engines over 50 rated brake horsepower (bhp), operated at facilities located in industrial and commercial areas throughout the entire SCAQMD jurisdiction. The SCAQMD has jurisdiction over an area of 10,473 square miles (referred to hereafter as the district), consisting of the four-county South Coast Air Basin (Basin) and the Riverside County portions of the Salton Sea Air Basin (SSAB) and the Mojave Desert

Air Basin (MDAB). The Basin, which is a subarea of the SCAQMD's jurisdiction, is bounded by the Pacific Ocean to the west and the San Gabriel, San Bernardino, and San Jacinto Mountains to the north and east. The 6,745 square-mile Basin includes all of Orange County and the nondesert portions of Los Angeles, Riverside, and San Bernardino counties. The Riverside County portion of the SSAB and MDAB is bounded by the San Jacinto Mountains in the west and spans eastward up to the Palo Verde Valley. The federal nonattainment area (known as the Coachella Valley Planning Area) is a subregion of both Riverside County and the SSAB and is bounded by the San Jacinto Mountains to the west and the eastern boundary of the Coachella Valley to the east (see Figure 1-1).

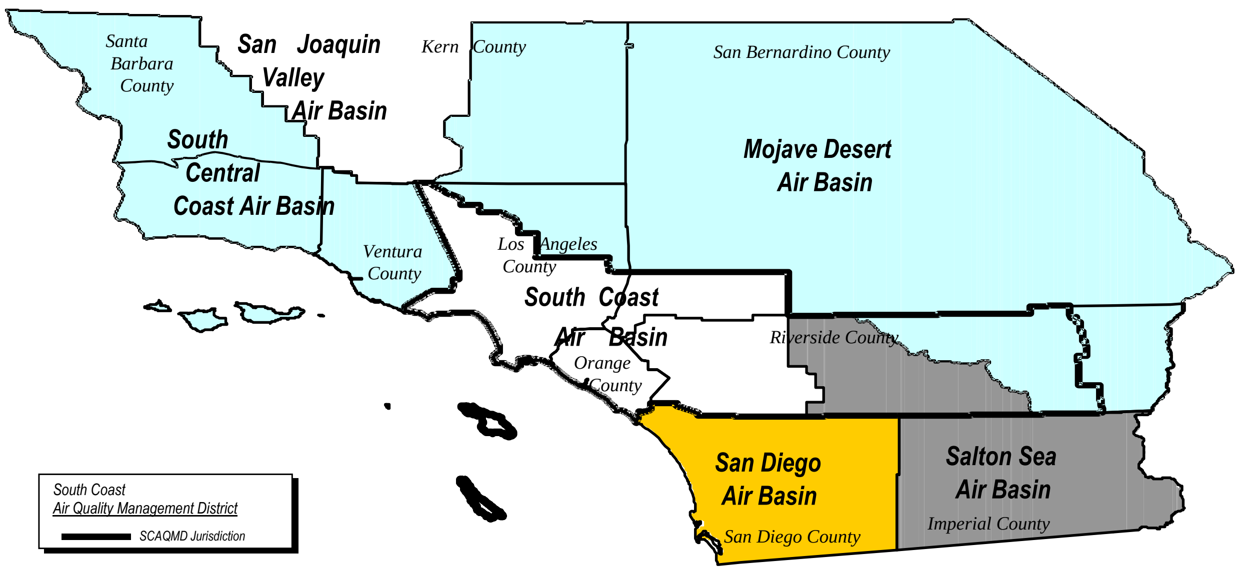

Figure 1-1 Boundaries of the South Coast Air Quality Management District

PROJECT DESCRIPTION

A summary of the proposed amendments follows:

Applicability

No change. PAR 1110.2 applies to all stationary and portable engines over 50 rated bhp.

Definitions

This subdivision lists keywords related to gaseous- and liquid fueled engines and defines them for clarity and to enhance enforceability. A new definition for "breakdown" is proposed to support the new requirements previously discussed.

Requirements
Operators of affected biogas operations would be required to comply with the concentration limits in Table 1-1 by January 1, 2017.

Table 1-1 Proposed Concentration Limits for Biogas Engines

Concentration Limits Effective January 1, 2017		
NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
11	30	250

1Corrected to 15 percent oxygen on a dry basis and averaged over 15 minutes.
Measured as carbon, corrected to 15 percent oxygen on a dry basis and averaged over required sampling time.
3 ECF is the efficiency correction factor.

For the City of San Bernardino and Eastern Municipal Water District that commenced and implemented technology demonstration projects prior to January 1, 2015, all of their biogas engines would have until January 1, 2018 to comply with the requirements of Table 1-1.

Monitoring, Testing and Recordkeeping
The primary focus of the proposed amendments in this subdivision is to limit the number of breakdowns and emissions during breakdown events of stationary engines (f)(1)(D)-Inspection and Monitoring Plan, in order to be consistent with the recent EPA final action on startup, shutdown, and malfunction Emissions.

Since subparagraph D pertains to NOx only, engines that have NOx CEMS and do not have CO CEMS are not subject to subparagraph D.

Alternate Compliance Option
The current rule allows in lieu of complying with the applicable emissions limits by the effective date specified in Table III-B of the rule, may defer compliance by up to two years. The proposed amendment will allow operators of biogas-fired units to defer compliance in quarterly increments up to one additional year.

PROJECT BACKGROUND

Regulatory History
Rule 1110.2 – Emissions from Gaseous- and Liquid-Fired Engines was adopted by the AQMD Governing Board on August 3, 1990. It required that either 1) NOx emissions be reduced over 90% to one of two compliance limits specified by the rule, or; 2) the engines be permanently removed from service or replaced with electric motors. It was amended in September 1990 to clarify rule language and then amended in August and December of 1994 to modify the CO monitoring requirements and to clarify rule language. The amendment of November 1997 eliminated the requirement for continuous monitoring of CO, reduced the source testing requirement from once every year to once every three years, and exempted non-road engines, including portable engines, from most requirements. The amendment in June 2005 made the previously exempt agricultural engines subject to the rule.

To address widespread non-compliance with stationary IC engines, the 2008 amendment augmented the source testing, continuous monitoring, inspection and maintenance (I&M), and reporting requirements of the rule to improve compliance. It also required stationary, non-emergency engines to meet emission standards equivalent to current BACT for NOx and VOC and almost to BACT for CO. This partially implemented the 2007 AQMP control measure for Facility Modernization (MCS-001). Additionally, the 2008 amendment required new electric generating engines to limit emissions to levels nearly equivalent to large central power plants, meeting standards that are at or near the CARB 2007 Distributed Generation Emissions Standards. It also clarified the status for portable engines and set emissions standards for biogas engines to become effective on July 1, 2012 if the July 2010 Technology Assessment would confirm the achievability of those limits.

The 2008 adopting resolution included commitments directing staff to conduct a Technology Assessment to address the availability, feasibility, cost-effectiveness, compliance schedule, and global warming gas impacts of biogas engine control technologies and report back to the Governing Board no later than July 2010. Additionally, the Governing Board directed that the July 2012 biogas emission limits would not be incorporated into the SIP unless the July 2010 Technology Assessment found that the proposed limits are achievable and cost-effective.
The amendment in July 2010 added an exemption to the rule affecting a remote public safety communications site at Santa Rosa Peak in Riverside County which has limited accessibility in the wintertime.

At the July 2010 Governing Board meeting, staff presented an Interim Technology Assessment to address the board resolution commitments in 2008. The Interim Technology Assessment summarized the biogas engine control technologies to date and the status of on-going demonstration projects. Due to the delays caused by the permit moratorium in 2009, the release of a subsequent report was recommended upon the completion of these projects. The Interim Technology Assessment concluded that feasible, cost-effective technology should be available that can support the feasibility of the July 2012 emission limits, but that the delay in the demonstration projects would likely necessitate an adjustment to the July 1, 2012 compliance date of Rule 1110.2.

The September 2012 amendments established a compliance date of January 1, 2016 for biogas engines. A compliance option was also provided so that operators requiring additional time would be given up to two years beyond the compliance date with the submittal of a compliance plan and payment of a compliance flexibility fee. In addition, SCAQMD staff presented an Assessment of Available Technology for Control of NOx, CO, and VOC Emissions from Biogas-Fueled Engines that detailed the different available technologies and demonstration projects for biogas engines, along with costs.

Extension of the Compliance Date for Biogas Engines

Since the amendments to Rule 1110.2 on September 7, 2012, SCAQMD staff has met with the stakeholders periodically, both in public forums and through individual meetings for updates on technology implementation. Based on feedback from these operators, some installations will take longer to install than expected and will reach full compliance after the current deadline of January 1, 2016. The range of implementation dates ranged from about mid-2016 to mid-2018.
On March 31, 2011, the Orange County Sanitation District (OCSD) completed a one year pilot study demonstration of biogas cleanup with oxidation catalyst and SCR. Since that time, the system has continued to meet the future limits of the rule and the operator is currently in the process of retrofitting the remaining engines at its two facilities with the same technology. However, since there is a total of seven engines requiring retrofits, the overall project completion

date will be after January 1, 2016. Other operators have similar timelines and have expressed their concerns to SCAQMD staff about meeting the January 1, 2016 deadline.

Two biogas technology demonstration projects are currently underway. One is the NOxTech system at Eastern Municipal Water District's Temecula plant. NOxTech utilizes selective non-catalytic reduction (SNCR) without the necessity for fuel gas pretreatment. Although some preliminary data has shown that the system is capable of reducing NOx from digester gas fueled engines down to 11 ppm, consistent performance is something that the facility is still fine tuning. Based on the results of further testing of this unit, the technology may also be installed at another facility that operates one digester gas engine.

The second technology demonstration project is the hydrogen assisted lean operation (HALO) with partial oxidation gas turbine (POGT), and it is currently underway at the City of San Bernardino Municipal Water Department. This technology employs hydrogen enrichment of the digester gas than results in leaner operation of the engine which reduces NOx emissions. The project has been partially funded with money from the SCAQMD along with the state. The project was awarded to the Gas Technology Institute (GTI) for fabrication and installation. The fabrication and installation has experienced some setbacks which have resulted in delays of the delivery of essential components belonging to the new system. The City of San Bernardino is hoping to use the results of this demonstration project, which will be utilized for only one engine, to possibly retrofit the remaining engines at the facility, which amount to five in total. Given the setbacks and delays, the operators feel that they will have a difficult time implementing the technology by 2018.

Based on the feedback from the regulated facility operators, SCAQMD staff is proposing to extend the compliance deadline for biogas engines beyond January 1, 2017.

EPA's Ruling on Excess Emissions Due to Breakdowns

According to EPA Region IX staff, the current Rule 1110.2 language suggests that sources might be protected from enforcement for even gross emission violations during preventable breakdowns. Under this assessment, the rule language is in contrast to national policy as described in EPA's recent supplemental notice of proposed rulemaking on excess emissions from startup, shutdown, and malfunction on 79 FR 55920 (9/17/2014). The subject rule language originated in the February 2, 2008 amendment. However, EPA Region IX's comments refer to the July 9, 2010 amendment. The inconsistency with the rule language with EPA national policy precludes their ability to fully approve the rule.

To resolve EPA's issue with potential gross emission violations during preventable breakdowns, corrective actions have been proposed in the context of changes to Rule 1110.2. Not resolving this issue will result in EPA not approving the 2010 amendment into the State Implementation Plan (SIP). If this disapproval is finalized, sanctions would be imposed unless the U.S. EPA approves subsequent SIP revisions that correct the rule deficiencies within 18 months of disapproval.

A final disapproval would also trigger the two-year clock for the Federal Implementation Plan (FIP) requirement. It should be noted that the submitted rule has been adopted by the SCAQMD, and U.S. EPA's final limited disapproval would not prevent the SCAQMD from enforcing it.

Affected Industries

Rule 1110.2 applies to stationary and portable reciprocating internal combustion engines (ICEs) over 50 brake horsepower (bhp). PAR 1110.2 also affects the subset of engines that are fueled with biogas, which are those that are operated by landfills and wastewater treatment plants. Biogas engines are typically lean-burn engines that operate similarly to lean-burn natural gas-fired engines with a higher level of exhaust oxygen.

Landfills produce gas that results from the breakdown of municipal solid waste. This gas is primarily composed of methane and carbon dioxide. The gas is collected in a series of wells that transports it via pipeline to the landfill gas fired engines. The collected landfill gas fires one or more biogas engines with or without supplementation of natural gas.

Wastewater treatment plants produce digester gas from the plant's digesters. A digester uses heat and bacteria in an oxygen-free (anaerobic) environment to break down sewage sludge. A by-product of this process is biogas that contains methane. This biogas also fires one or more biogas engines with or without supplementation of natural gas. An advantage with using ICEs at wastewater treatment plants is that these are combined heat and power (CHP) units. The waste heat created by the engine can be recovered and used to heat the plant's digesters, resulting in energy savings.

Whether coming from a landfill or an anaerobic digester, the biogas is used to fire an internal combustion engine with a generator to produce electricity. Some facilities are self-generating facilities that use the electricity to power their processes internally. Others sell this generated power to the local utility grid. The wastewater treatment plants are primarily operated by public entities and utilities, while the landfills are operated by either public or private operators. There are a total of eight public operators and five private operators for biogas engines in the South Coast Basin.

There are currently 58 biogas engines operating in the Basin. Of these engines, 30 are digester gas-fueled and 28 are landfill gas-fueled. These engines are operated by 13 independent operators at 22 locations (6 operate digester gas-fueled engines and 7 operate landfill gas-fueled engines).

Despite past efforts to reduce emissions, biogas-fueled engines remain the dirtiest in terms of mass per unit power produced in the Basin, even though they are fired with renewable fuel. Even at BACT, these engines pollute significantly more than large central generating stations on a pound per megawatt-hour basis (Figure 2). For biogas ICEs, the NOx emissions are over 25 times higher than those of central power plants, 119 times higher for VOC, and 75 times higher for CO.

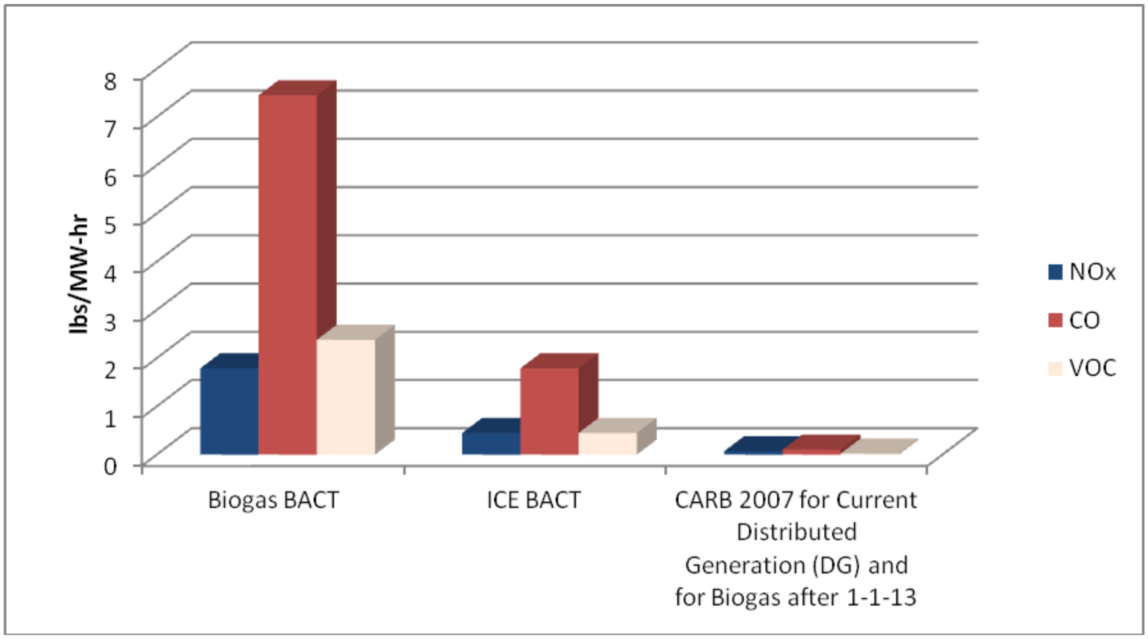

Figure 1-2. Current BACT for Biogas ICEs and Natural Gas ICEs vs. Central Generating Station BACT

During the 2010 Interim Technology Assessment, approximately 66 engines fueled by biogas were identified. Since that time, however, the number has decreased to 58 due to some engines being placed out of service. Nonetheless, the remaining biogas engines in operation are among the top NOx emitters amongst stationary, non-emergency engines.

For the proposed amendments pertaining to EPA's concerns over equipment breakdowns and excess emissions, these requirements would apply to all operators of gaseous- and liquid-fueled engines governed by this rule.

PROJECT ALTERNATIVES

The Draft SEA will discuss and compare alternatives to the proposed project as required by CEQA and by SCAQMD Rule 110. Alternatives must include realistic measures for attaining the basic objectives of the proposed project and provide a means for evaluating the comparative merits of each alternative. In addition, the range of alternatives must be sufficient to permit a reasoned choice and it need not include every conceivable project alternative. The key issue is whether the selection and discussion of alternatives fosters informed decision making and public participation. A CEQA document need not consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative.

SCAQMD Rule 110 does not impose any greater requirements for a discussion of project alternatives in an environmental assessment than is required for an Environmental Impact Report under CEQA. Alternatives will be developed based in part on the major components of the proposed rule. The rationale for selecting alternatives rests on CEQA's requirement to present "realistic" alternatives; that is alternatives that can actually be implemented. CEQA also requires an evaluation of a "No Project Alternative."

SCAQMD's policy document Environmental Justice Program Enhancements for fiscal year (FY) 2002-03, Enhancement II-1 recommends that all SCAQMD CEQA assessments include a feasible project alternative with the lowest air toxics emissions. In other words, for any major equipment or process type under the scope of the proposed project that creates a significant environmental impact, at least one alternative, where feasible, shall be considered from a "least harmful" perspective with regard to hazardous air emissions.

The Governing Board may choose to adopt any portion or all of any alternative presented in the Draft SEA. The Governing Board is able to adopt any portion or all of any of the alternatives presented because the impacts of each alternative will be fully disclosed to the public and the public will have the opportunity to comment on the alternatives and impacts generated by each alternative.

Written suggestions on potential project alternatives received during the comment period for the Initial Study will be considered when preparing the Draft SEA.

CHAPTER 2 –ENVIRONMENTAL CHECKLIST

INTRODUCTION

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

GENERAL INFORMATION

Project Title:	Proposed Amended Rule 1110.2
Lead Agency Name:	South Coast Air Quality Management District
Lead Agency Address:	21865 Copley Drive, Diamond Bar, CA 91765
Rule Contact Person:	Kevin Orellana, (909) 396-3492
CEQA Contact Person:	Cynthia Carter, (909) 396-2431
Project Sponsor's Name:	South Coast Air Quality Management District
Project Sponsor's Address:	21865 Copley Drive, Diamond Bar, CA 91765
General Plan Designation:	Not applicable
Zoning:	Not applicable
Description of Project:	The proposed project affects all stationary and portable engines over 50 rated brake horsepower within the SCAQMD jurisdiction. Rule 1110.2 limits NOx, VOC, and CO emissions from the combustion of gaseous- and liquid-fueled engines. Under PAR 1110.2, biogas-fired engines would have additional time to comply with the rule's emission limits. Additionally, limits will be placed on the number of breakdowns and emissions during breakdown events for all engines. Other minor changes are proposed for clarity and consistency throughout the rule.
Surrounding Land Uses and Setting:	Not applicable
Other Public Agencies Whose Approval is Required:	None

ENVIRONMENTAL FACTORS POTENTIALLY AFFECTED

The following environmental impact issues have been assessed to determine their potential to be affected by the proposed project. As indicated by the checklist on the following pages, environmental topics marked with an "✓" may be adversely affected by the proposed project. An explanation relative to the determination of the significance of the impacts can be found following the checklist for each area.

☐	Aesthetics	☐	Geology and Soils	☐	Population and Housing
☐	Agricultural Resources	☐	Hazards and Hazardous Materials	☐	Public Services
☑	Air Quality and GHG	☐	Hydrology and Water Quality	☐	Recreation
☐	Biological Resources	☐	Land Use and Planning	☐	Solid/Hazardous Waste
☐	Cultural Resources	☐	Mineral Resources	☐	Transportation/Traffic
☐	Energy	☐	Noise	☑	Mandatory Findings

DETERMINATION

On the basis of this initial evaluation:

☐ I find the proposed project, in accordance with those findings made pursuant to CEQA Guideline §15252, COULD NOT have a significant effect on the environment, and that a SUSEQUENT ENVIRONMENTAL ASSESSMENT with no significant impacts has been prepared.

☐ I find that although the proposed project could have a significant effect on the environment, there will NOT be significant effects in this case because revisions in the project have been made by or agreed to by the project proponent. A SUBSEQUENT ENVIRONMENTAL ASSESSMENT with no significant impacts will be prepared.

☑ I find that the proposed project MAY have a significant effect(s) on the environment, and a SUBSEQUENT ENVIRONMENTAL ASSESSMENT will be prepared.

☐ I find that the proposed project MAY have a "potentially significant impact" on the environment, but at least one effect 1) has been adequately analyzed in an earlier document pursuant to applicable legal standards, and 2) has been addressed by mitigation measures based on the earlier analysis as described on attached sheets. A SUBSEQUENT ENVIRONMENTAL ASSESSMENT is required, but it must analyze only the effects that remain to be addressed.

☐ I find that although the proposed project could have a significant effect on the environment, because all potentially significant effects (a) have been analyzed adequately in an earlier ENVIRONMENTAL ASSESSMENT pursuant to applicable standards, and (b) have been avoided or mitigated pursuant to that earlier ENVIRONMENTAL ASSESSMENT, including revisions or mitigation measures that are imposed upon the proposed project, nothing further is required.

Date: July 28, 2015 **Signature:** Jillian Wong

Jillian Wong, Ph.D.
Program Supervisor, CEQA Section
Planning, Rules, and Area Sources

DISCUSSION AND EVALUATION OF ENVIRONMENTAL IMPACTS

As discussed in Chapter 1, implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. This amendment would apply to all stationary and portable reciprocating ICEs over 50 bhp and is necessary for Rule 1110.2 SIP approval. Therefore, no new physical changes requiring construction are involved with the proposed project.

The original analysis of the construction activities associated with construction of demonstration projects at the biogas facilities is contained in the CEQA document for Rule 1110.2, the Final Environmental Assessment for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines (ICEs), certified by the SCAQMD Governing Board on February 1, 2008 (SCAQMD No. 280307JK)[4]. This CEQA document will be referred to herein as the December 2007 Final EA. For the aforementioned reasons, the following analysis will focus on the effect of PAR 1110.2 in terms of NOx, VOC, and CO emissions reductions delayed (i.e., emissions reductions that would have occurred according to the original compliance schedule if the original requirements in Rule 1110.2 were implemented) as a result of delaying the compliance dates and not the environmental effects of the construction activities since there will be no new physical changes associated with PAR 1110.2.

[4] http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2008/rule-1110.2/finalea.pdf

ENVIRONMENTAL CHECKLIST AND DISCUSSION

I. AESTHETICS.

Would the project:	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
a) Have a substantial adverse effect on a scenic vista?	☐	☐	☐	☑
b) Substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?	☐	☐	☐	☑
c) Substantially degrade the existing visual character or quality of the site and its surroundings?	☐	☐	☐	☑
d) Create a new source of substantial light or glare which would adversely affect day or nighttime views in the area?	☐	☐	☐	☑

SIGNIFICANCE CRITERIA

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

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

DISCUSSION

I. a), b), c) & d) Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. The original analysis of the construction activities associated with construction at the biogas facilities is contained in the December 2007 Final EA. Therefore, no new physical changes requiring construction are involved with the proposed project. Therefore, PAR 1110.2 is not expected to degrade the visual character of any site where a facility is located and that operates an affected unit or its surroundings, affect any scenic vista, damage scenic resources. Further, since PAR 1110.2 does not require existing facilities to operate at night, no new sources of substantial light or glare are expected.

Based upon these considerations, no significant aesthetics impacts are expected from the implementation of PAR 1110.2 and as such, the topic of aesthetics will not be further analyzed in the Draft SEA. Since no significant aesthetics impacts were identified, no mitigation measures are necessary or required.

II. AGRICULTURE AND FOREST RESOURCES.

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

SIGNIFICANCE CRITERIA

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

- The proposed project conflicts with existing zoning or agricultural use or Williamson Act contracts.
- The proposed project will convert prime farmland, unique farmland or farmland of statewide importance as shown on the maps prepared pursuant to the farmland mapping and monitoring program of the California Resources Agency, to non-agricultural use.
- The proposed project conflicts with existing zoning for, or causes rezoning of, forest land (as defined in Public Resources Code §12220(g)), timberland (as defined in Public Resources Code §4526), or timberland zoned Timberland Production (as defined by Government Code § 51104 (g)).
- The proposed project would involve changes in the existing environment, which due to their location or nature, could result in conversion of farmland to non-agricultural use or conversion of forest land to non-forest use.

DISCUSSION

II. a), b), c) & d) Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. The original analysis of the construction activities associated with construction at the biogas facilities is contained in the December 2007 Final EA. Therefore, no new physical changes requiring construction are involved with the proposed project.

PAR 1110.2 it will only affect combustion equipment primarily located at existing facilities in industrial or commercial areas. No agricultural resources including Williamson Act contracts are located within or would be impacted by the proposed project. PAR 1110.2 would not result in any new construction of buildings or other structures that would convert any classification of farmland to non-agricultural use or conflict with zoning for agricultural use or a Williamson Act contract.

PAR 1110.2 would also not result in any new construction of buildings or other structures that would cause the loss of forest land or conversion of forest land to non-forest use. Since there are no forestry resources or operations on or near the affected facilities, PAR 1110.2 would not conflict with existing zoning for, or cause rezoning of, forest land (as defined in Public Resources Code §12220(g)), timberland (as defined by Public Resources Code §4526), or timberland zoned Timberland Production (as defined by Government Code §51104 (g).

Lastly, since PAR 1110.2 would not substantially change the facility, there are no provisions in PAR 1110.2 that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments and no land use or planning requirements relative to agriculture and forest resources will be altered by PAR 1110.2.

Based upon these considerations, no significant agriculture and forest resources impacts are expected from the proposed project and as such, the topic of agriculture and forest resources will not be further analyzed in the Draft SEA. Since no significant agriculture and forest resources impacts were identified, no mitigation measures are necessary or required.

III. AIR QUALITY AND GREENHOUSE GAS EMISSIONS

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

SIGNIFICANCE CRITERIA

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

To determine whether or not greenhouse gas emissions from the proposed project may be significant, impacts will be evaluated and compared to the 10,000 MT CO2/year threshold for industrial sources.

Table 2-1 SCAQMD Air Quality Significance Thresholds

Mass Daily Thresholds [a]		
Pollutant	**Construction** [b]	***Operation*** [c]
NOx	100 lbs/day	55 lbs/day
VOC	75 lbs/day	55 lbs/day
PM10	150 lbs/day	150 lbs/day
PM2.5	55 lbs/day	55 lbs/day
SOx	150 lbs/day	150 lbs/day
CO	550 lbs/day	550 lbs/day
Lead	3 lbs/day	3 lbs/day
Toxic Air Contaminants (TACs), Odor, and GHG Thresholds		
TACs (including carcinogens and non-carcinogens)	Maximum Incremental Cancer Risk ≥ 10 in 1 million Cancer Burden > 0.5 excess cancer cases (in areas ≥ 1 in 1 million) Chronic & Acute Hazard Index ≥ 1.0 (project increment)	
Odor	Project creates an odor nuisance pursuant to SCAQMD Rule 402	
GHG	10,000 MT/yr CO2eq for industrial facilities	
Ambient Air Quality Standards for Criteria Pollutants [d]		
NO2 1-hour average annual arithmetic mean	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 0.18 ppm (state) 0.03 ppm (state) and 0.0534 ppm (federal)	
PM10 24-hour average annual average	 10.4 μg/m^3 (construction)[e] & 2.5 μg/m^3 (operation) 1.0 μg/m^3	
PM2.5 24-hour average	 10.4 μg/m^3 (construction)[e] & 2.5 μg/m^3 (operation)	
SO2 1-hour average 24-hour average	 0.25 ppm (state) & 0.075 ppm (federal – 99th percentile) 0.04 ppm (state)	
Sulfate 24-hour average	 25 μg/m^3 (state)	
CO 1-hour average 8-hour average	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 20 ppm (state) and 35 ppm (federal) 9.0 ppm (state/federal)	
Lead 30-day Average Rolling 3-month average	 1.5 μg/m^3 (state) 0.15 μg/m^3 (federal)	

[a] Source: SCAQMD CEQA Handbook (SCAQMD, 1993)
[b] Construction thresholds apply to both the South Coast Air Basin and Coachella Valley (Salton Sea and Mojave Desert Air Basins).
[c] For Coachella Valley, the mass daily thresholds for operation are the same as the construction thresholds.
[d] Ambient air quality thresholds for criteria pollutants based on SCAQMD Rule 1303, Table A-2 unless otherwise stated.
[e] Ambient air quality threshold based on SCAQMD Rule 403.

KEY: lbs/day = pounds per day ppm = parts per million μg/m^3 = microgram per cubic meter ≥ = greater than or equal to
MT/yr CO2eq = metric tons per year of CO2 equivalents > = greater than

DISCUSSION

III. a), b), c), d), e), & f) Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. The original analysis of the construction activities associated with construction at the biogas facilities is contained in the December 2007 Final EA. Therefore, no new physical changes requiring construction are involved with the proposed project.

<u>Construction Impacts</u>

The original analysis of the construction activities associated with construction at the biogas facilities is contained in the CEQA document for Rule 1110.2, the Final Environmental Assessment for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines (ICEs), certified by the SCAQMD Governing Board on February 1, 2008 (SCAQMD No. 280307JK)[5]. Therefore, the air quality impacts associated with construction at the biogas facilities have been adequately analyzed previously and will not be included in the Draft SEA.

<u>Operation Impacts</u>

PAR 1110.2 will result in a delay of: 0.9 tons/day of NOx, 0.5 tons/day of VOC, and 20 tons/day of CO emission reductions. However, these delayed emission reductions will be recaptured in compliance years 2017 and 2018, respectively.

For the aforementioned reasons, PAR 1110.2 has the potential to conflict with or obstruct implementation of the air quality management plan, violate an air quality standard, result in a cumulatively considerable net increase of a criteria pollutant, expose sensitive receptors to substantial pollutant concentrations, create objectionable odors, and diminish an existing air quality rule and these impacts will be further evaluated in the Draft SEA. The Draft SEA will analyze the effect of PAR 1110.2 in terms of NOx, VOC, and CO emissions reductions delayed (i.e., emissions reductions that would have occurred according to the original compliance schedule if the original requirements in Rule 1110.2 were implemented) as a result of delaying the compliance dates and not the environmental effects of the construction activities since there will be no new physical changes associated with PAR 1110.2. If air quality impacts are found to be significant in the Draft SEA, mitigation measures will be identified.

III. g) & h) PAR 1110.2 also affects the subset that contains engines fueled with biogas, which are those that are operated by landfills and wastewater treatment plants. Landfills produce gas that results from the breakdown of municipal solid waste. This gas is primarily composed of methane and carbon dioxide. The biogas is used to fire an internal combustion engine with a generator to produce electricity. Some facilities are self-generating facilities that use the electricity to power their processes internally. Others sell off this generated power to the local utility grid. The wastewater treatment plants are primarily operated by public entities and utilities, while the landfills are operated by either public or private operators. There are a total of 8 public operators and 5 five private operators for biogas engines in the South Coast Basin.

[5] http://www.aqmd.gov/docs/default-source/ceqa/documents/aqmd-projects/2008/rule-1110.2/finalea.pdf

There are 55 biogas engines operating in the Basin. Of these engines, 27 are digester gas-fueled and 28 are landfill gas-fueled. These engines are operated by 13 independent operators at 22 locations (6 operate digester gas-fueled engines and 7 operate landfill gas-fueled engines). PAR 1110.2 will allow the biogas-fired engines additional time to comply with the emission limits in the rule and will result in a delay of: 0.9 tons/day of NOx, 0.5 tons/day of VOC, and 20 tons/day of CO emission reductions. The GHG impacts associated with PAR 1110.2 will be analyzed in the Draft SEA. If GHG impacts are found to be significant in the Draft SEA, mitigation measures will be identified.

IV. BIOLOGICAL RESOURCES.

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

SIGNIFICANCE CRITERIA

Impacts on biological resources will be considered significant if any of the following criteria apply:

- The project results in a loss of plant communities or animal habitat considered to be rare, threatened or endangered by federal, state or local agencies.
- The project interferes substantially with the movement of any resident or migratory wildlife species.
- The project adversely affects aquatic communities through construction or operation of the project.

DISCUSSION

IV. a), b), c), d), e), & f) Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. The original analysis of the construction activities associated with construction at the biogas facilities is contained in the December 2007 Final EA. Therefore, no new physical changes requiring construction are involved with the proposed project. In general, the areas where affected equipment is located currently do not typically support riparian habitat, federally protected wetlands, or migratory corridors. Additionally, special status plants, animals, or natural communities are not expected to be found in close proximity to the affected facilities.

PAR 1110.2 is not envisioned to conflict with local policies or ordinances protecting biological resources nor local, regional, or state conservation plans because it will only affect combustion equipment primarily located at existing facilities in industrial or commercial areas. Additionally, PAR 1110.2 will not conflict with any adopted Habitat Conservation Plan, Natural Community Conservation Plan, or any other relevant habitat conservation plan for the same reason.

The SCAQMD, as the Lead Agency for the proposed project, has found that, when considering the record as a whole, there is no evidence that PAR 1110.2 will have potential for any new adverse effects on wildlife resources or the habitat upon which wildlife depends. Accordingly, based upon the preceding information, the SCAQMD has, on the basis of substantial evidence, rebutted the presumption of adverse effect contained in §753.5 (d), Title 14 of the California Code of Regulations.

Based upon these considerations, no significant biological resources impacts are anticipated and as such, the topic of biological resources will not be further analyzed in the Draft SEA. Since no significant adverse biological resources impacts were identified, no mitigation measures are necessary or required.

V. CULTURAL RESOURCES.

Would the project:	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
a) Cause a substantial adverse change in the significance of a historical resource as defined in §15064.5?	☐	☐	☐	☑
b) Cause a substantial adverse change in the significance of an archaeological resource as defined in §15064.5?	☐	☐	☐	☑
c) Directly or indirectly destroy a unique paleontological resource, site, or feature?	☐	☐	☐	☑
d) Disturb any human remains, including those interred outside formal cemeteries?	☐	☐	☐	☑
e) Cause a substantial adverse change in the significance of a tribal cultural resource as defined in Public Resources Code §21074?	☐	☐	☐	☑

SIGNIFICANCE CRITERIA

Impacts to cultural resources will be considered significant if:

- The project results in the disturbance of a significant prehistoric or historic archaeological site or a property of historic or cultural significance to a community or ethnic or social group.
- Unique paleontological resources are present that could be disturbed by construction of the proposed project.
- The project would disturb human remains.

DISCUSSION

V. a), b), c), & d) Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. The original analysis of the construction activities associated with construction at the biogas facilities is contained in the December 2007 Final EA. Therefore, no new physical changes requiring construction are involved with the proposed project. Thus, no impacts to historical resources are expected to occur as a result of implementing PAR 1110.2.

PAR 1110.2 will only affect combustion equipment primarily located at existing facilities in industrial or commercial areas and is not expected to require physical changes to the environment, which may disturb paleontological or archaeological resources. Furthermore, it is envisioned that these areas are already either devoid of significant cultural resources or whose cultural resources have been previously disturbed. Therefore, the proposed project has no potential to cause a substantial adverse change to a historical or archaeological resource, directly or indirectly destroy a unique paleontological resource or site or unique geologic feature, or disturb any human remains, including those interred outside a formal cemeteries. PAR 1110.2 is, therefore, not anticipated to result in any activities or promote any programs that could have a significant adverse impact on cultural resources in the District. PAR 1110.2 is, therefore, not anticipated to result in any activities or promote any programs that could have a significant adverse impact on cultural resources in the District.

V. e) The proposed project is not expected to require physical changes to a site, feature, place, cultural landscape, sacred place or object with cultural value to a California Native American Tribe. Furthermore, the proposed project is not expected to result in a physical change to a resource determined to be eligible for inclusion or listed in the California Register of Historical Resources or included in a local register of historical resources. For these reasons, the proposed project is not expected to cause any substantial adverse change in the significance of a tribal cultural resource as defined in Public Resources Code §21074.

It is important to note that as part of releasing this CEQA document for public review and comment, the SCAQMD also provided a formal notice of the proposed project to all California Native American Tribes (Tribes) that requested to be on the Native American Heritage Commission’s (NAHC) notification list per Public Resources Code §21080.3.1 (b)(1). The NAHC notification list provides a 30-day period during which a Tribe may respond to the formal notice, in writing, requesting consultation on the proposed project.

In the event that a Tribe submits a written request for consultation during this 30-day period, the SCAQMD will initiate a consultation with the Tribe within 30 days of receiving the request in accordance with Public Resources Code §21080.3.1 (b). Consultation ends when either: 1) both parties agree to measures to avoid or mitigate a significant effect on a Tribal Cultural Resource and agreed upon mitigation measures shall be recommended for inclusion in the environmental document [see Public Resources Code §21082.3 (a)]; or, 2) either party, acting in good faith and after reasonable effort, concludes that mutual agreement cannot be reached [see Public Resources Code §21080.3.2 (b)(1)-(2) and §21080.3.1 (b)(1)].

Based upon these considerations, significant adverse cultural resources impacts are not expected from implementing the proposed project and will not be further assessed in the Draft SEA. Since no significant cultural resources impacts were identified, no mitigation measures are necessary or required.

VI. ENERGY.

Would the project:	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
a) Conflict with adopted energy conservation plans?	☐	☐	☐	☑
b) Result in the need for new or substantially altered power or natural gas utility systems?	☐	☐	☐	☑
c) Create any significant effects on local or regional energy supplies and on requirements for additional energy?	☐	☐	☐	☑
d) Create any significant effects on peak and base period demands for electricity and other forms of energy?	☐	☐	☐	☑
e) Comply with existing energy standards?	☐	☐	☐	☑

SIGNIFICANCE CRITERIA

Impacts to energy and mineral resources will be considered significant if any of the following criteria are met:

- The project conflicts with adopted energy conservation plans or standards.
- The project results in substantial depletion of existing energy resource supplies.
- An increase in demand for utilities impacts the current capacities of the electric and natural gas utilities.
- The project uses non-renewable resources in a wasteful and/or inefficient manner.

DISCUSSION

VI. a), b), c), d) & e) Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. The original analysis of the construction activities associated with construction at the biogas facilities is contained in the December 2007 Final EA. Therefore, no new physical changes requiring construction are involved with the proposed project. As a result, PAR 1110.2 would not conflict with energy conservation plans, use non-renewable resources in a wasteful manner, or result in the need for new or substantially altered power or natural gas systems. Since PAR 1110.2 would primarily affect existing equipment operating at existing facilities, the proposed project will not conflict with adopted energy conservation plans because existing facilities would be expected to continue implementing any existing energy conservation plans. Additionally, operators of affected facilities are expected to comply with existing energy conservation plans and standards to minimize operating costs, while still complying with the requirements of PAR 1110.2.

PAR 1110.2 would not create any significant effects on peak and base period demands for electricity and other forms of energy since no construction of buildings or other structures are anticipated. PAR 1110.2 is not expected to use energy in a wasteful manner, and will not exceed SCAQMD energy significance thresholds. There will be no substantial depletion of energy resources nor will significant amounts of fuel be needed when compared to existing supplies.

Therefore, PAR 1110.2 is not expected to generate significant adverse energy resources impacts and as such, the topic of energy will not be discussed further in the Draft SEA. Since no significant energy impacts were identified, no mitigation measures are necessary or required.

VII. GEOLOGY AND SOILS.

Would the project:	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
a) Expose people or structures to potential substantial adverse effects, including the risk of loss, injury, or death involving:	☐	☐	☐	☑
• Rupture of a known earthquake fault, as delineated on the most recent Alquist-Priolo Earthquake Fault Zoning Map issued by the State Geologist for the area or based on other substantial evidence of a known fault?	☐	☐	☐	☑
• Strong seismic ground shaking?	☐	☐	☐	☑
• Seismic–related ground failure, including liquefaction?	☐	☐	☐	☑
b) Result in substantial soil erosion or the loss of topsoil?	☐	☐	☐	☑
c) Be located on a geologic unit or soil that is unstable or that would become unstable as a result of the project, and potentially result in on- or off-site landslide, lateral spreading, subsidence, liquefaction or collapse?	☐	☐	☐	☑
d) Be located on expansive soil, as defined in Table 18-1-B of the Uniform Building Code (1994), creating substantial risks to life or property?	☐	☐	☐	☑
e) Have soils incapable of adequately supporting the use of septic tanks or alternative wastewater disposal systems where sewers are not available for the disposal of wastewater?	☐	☐	☐	☑

SIGNIFICANCE CRITERIA

Impacts on the geological environment will be considered significant if any of the following criteria apply:

- Topographic alterations would result in significant changes, disruptions, displacement, excavation, compaction or over covering of large amounts of soil.
- Unique geological resources (paleontological resources or unique outcrops) are present that could be disturbed by the construction of the proposed project.

- Exposure of people or structures to major geologic hazards such as earthquake surface rupture, ground shaking, liquefaction or landslides.
- Secondary seismic effects could occur which could damage facility structures, e.g., liquefaction.
- Other geological hazards exist which could adversely affect the facility, e.g., landslides, mudslides.

DISCUSSION

VII. a) Southern California is an area of known seismic activity. Structures must be designed to comply with the Uniform Building Code Zone 4 requirements if they are located in a seismically active area. The local city or county is responsible for assuring that a proposed project complies with the Uniform Building Code as part of the issuance of the building permits and can conduct inspections to ensure compliance. The Uniform Building Code is considered to be a standard safeguard against major structural failures and loss of life. The goal of the code is to provide structures that will: 1) resist minor earthquakes without damage; 2) resist moderate earthquakes without structural damage but with some non-structural damage; and 3) resist major earthquakes without collapse but with some structural and non-structural damage.

The Uniform Building Code bases seismic design on minimum lateral seismic forces ("ground shaking"). The Uniform Building Code requirements operate on the principle that providing appropriate foundations, among other aspects, helps to protect buildings from failure during earthquakes. The basic formulas used for the Uniform Building Code seismic design require determination of the seismic zone and site coefficient, which represent the foundation conditions at the site. Accordingly, buildings and equipment at existing affected facilities are likely to conform to the Uniform Building Code and all other applicable state codes in effect at the time they were constructed.

Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. The original analysis of the construction activities associated with construction at the biogas facilities is contained in the December 2007 Final EA. Therefore, no new physical changes requiring construction are involved with the proposed project. As a result, substantial exposure of people or structure to the risk of loss, injury, or death involving seismic-related activities is not anticipated and will not be further analyzed in the Draft SEA.

VII. b), c) Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. The original analysis of the construction activities associated with construction at the biogas facilities is contained in the December 2007 Final EA. Therefore, no new physical changes requiring construction are involved with the proposed project. Therefore, changes in topography or surface relief features;

erosion of beach sand; or changes in existing siltation rates are not anticipated in response to the proposed project. Since PAR 1110.2 will only affect combustion equipment primarily located at existing facilities in industrial or commercial areas., it is expected that the soil types present at the affected facilities will not be further susceptible to expansion or liquefaction. Subsidence is not anticipated to be a problem since no excavation, grading, or filling activities will occur at affected facilities. Further, PAR 1110.2 would not involve drilling or removal of underground products (e.g., water, crude oil, et cetera) that could produce new, or make worse existing subsidence effects. Additionally, the affected areas are not envisioned to be prone to new risks from landslides or have unique geologic features since the affected facilities are located in industrial or commercial areas where such features have already been altered or removed. Finally, since affected equipment are located at existing facilities, PAR 1110.2 is not expected to alter or make worse any existing potential for subsidence, liquefaction, et cetera.

VII. d) & e) Since PAR 1110.2 will affect operations at existing facilities, it is expected that people or property will not be exposed to new impacts relative to expansive soils or soils incapable of supporting water disposal, nor will any existing impacts be made worse. Further, PAR 1110.2 would not require installation of septic tanks or other alternative waste water systems.

Based upon these considerations, no geology and soils impacts are expected from the implementation of PAR 1110.2 and as such, the topic of geology and soils will not be further analyzed in the Draft SEA. Since no significant geology and soils impacts were identified, no mitigation measures are necessary or required.

VIII. HAZARDS AND HAZARDOUS MATERIALS.

Would the project:	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
a) Create a significant hazard to the public or the environment through the routine transport, use, and disposal of hazardous materials?	☐	☐	☐	☑
b) Create a significant hazard to the public or the environment through reasonably foreseeable upset conditions involving the release of hazardous materials into the environment?	☐	☐	☐	☑
c) Emit hazardous emissions, or handle hazardous or acutely hazardous materials, substances, or waste within one-quarter mile of an existing or proposed school?	☐	☐	☐	☑
d) Be located on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code §65962.5 and, as a result, would create a significant hazard to the public or the environment?	☐	☐	☐	☑
e) For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public use airport or a private airstrip, would the project result in a safety hazard for people residing or working in the project area?	☐	☐	☐	☑
f) Impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan?	☐	☐	☐	☑
g) Expose people or structures to a significant risk of loss, injury or death involving wildland fires, including where wildlands are adjacent to urbanized areas or where residences are intermixed with wildlands?	☐	☐	☐	☑
h) Significantly increased fire hazard in areas with flammable materials?	☐	☐	☐	☑

SIGNIFICANCE CRITERIA

Impacts associated with hazards will be considered significant if any of the following occur:

- Non-compliance with any applicable design code or regulation.
- Non-conformance to National Fire Protection Association standards.
- Non-conformance to regulations or generally accepted industry practices related to operating policy and procedures concerning the design, construction, security, leak detection, spill containment or fire protection.
- Exposure to hazardous chemicals in concentrations equal to or greater than the Emergency Response Planning Guideline (ERPG) 2 levels.

DISCUSSION

VIII. a) Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. The original analysis of the construction activities associated with construction at the biogas facilities is contained in the December 2007 Final EA. Therefore, no new physical changes requiring construction are involved with the proposed project. There are no provisions in PAR 1110.2 that would increase the amount of hazardous materials used or generated by facility owners/operators. Therefore, no impacts are anticipated.

VIII. b) & h) Businesses are required to report increases in the storage or use of flammable and otherwise hazardous materials to local fire departments. As noted in item VIII. a), PAR 1110.2 is not expected to increase the amount of materials used or generated at affected facilities that would contain hazardous materials nor is it expected to significantly increase the demand of fuels (natural gas and liquid fuel) or other flammable substances.

In addition, local fire departments ensure that adequate permit conditions are in place to protect against potential risk of upset. The Uniform Fire Code and Uniform Building Code are set standards intended to minimize risks from flammable or otherwise hazardous materials. Local jurisdictions are required to adopt the uniform codes or comparable regulations. Local fire agencies require permits for the use or storage of hazardous materials and permit modifications for proposed increases in their use. Permit conditions depend on the type and quantity of the hazardous materials at the facility. Permit conditions may include, but are not limited to, specifications for sprinkler systems, electrical systems, ventilation, and containment. The fire departments make annual business inspections to ensure compliance with permit conditions and other appropriate regulations.

Further, all hazardous materials are expected to be used in compliance with established Occupational Safety and Health Administration (OSHA) or California Occupational Safety and Health Administration (CalOSHA) regulations and procedures, including providing adequate ventilation, using recommended personal protective equipment and clothing, posting appropriate signs and warnings, and providing adequate worker health and safety training. When taken together, the aforementioned regulations provide comprehensive measures to reduce hazards of explosive or otherwise hazardous materials. Compliance with these and other federal, state and local regulations and proper operation and maintenance of equipment should ensure the potential for explosions or accidental releases of hazardous materials is not significant.

VIII. c), e), & f) In general, the purpose of PAR 1110.2 is to maintain consistency with the startup, shutdown, and malfunction policy by the EPA and to bring compliance relief to owners/operators of affected combustion equipment by delaying compliance with the rule emission limits. While delaying implementation will delay some NOx, VOC, and CO emission reductions originally projected during the adoption of Rule 1110.2, eventually the overall emission reductions will be achieved from a large variety of combustion equipment at existing facilities, which will ultimately improve air quality and reduce adverse human health impact related to poor air quality. Since operations of these equipment categories occur primarily at existing facilities located in industrial or commercial areas, implementation of PAR 1110.2 is not expected to increase existing, or create any new hazardous emissions which would adversely affect existing/proposed schools or public/private airports located in close proximity to the affected facilities. Accordingly, these impact issues will not be further evaluated in the Draft SEA.

VIII. d) Even if some affected facilities are designated pursuant to Government Code §65962.5 as a large quantity generator of hazardous waste, it is not anticipated that complying with PAR 1110.2 will alter in any way how operators of affected facilities manage their hazardous wastes and that they will continue to be managed in accordance with all applicable federal, state, and local rules and regulations.

VIII. f) As discussed in VIII. a), PAR 1110.2 has no provisions that dictate the use of, or generate any new hazardous material. Therefore, it is not anticipated that PAR 1110.2 would require changes to impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan.

In addition, Health and Safety Code §25506 specifically requires all businesses handling hazardous materials to submit a business emergency response plan to assist local administering agencies in the emergency release or threatened release of a hazardous material. Business emergency response plans generally require the following:

- Identification of individuals who are responsible for various actions, including reporting, assisting emergency response personnel and establishing an emergency response team;
- Procedures to notify the administering agency, the appropriate local emergency rescue personnel, and the California Office of Emergency Services;
- Procedures to mitigate a release or threatened release to minimize any potential harm or damage to persons, property or the environment;
- Procedures to notify the necessary persons who can respond to an emergency within the facility;
- Details of evacuation plans and procedures;
- Descriptions of the emergency equipment available in the facility;
- Identification of local emergency medical assistance; and

- Training (initial and refresher) programs for employees in:
    1. The safe handling of hazardous materials used by the business;
    2. Methods of working with the local public emergency response agencies;
    3. The use of emergency response resources under control of the handler;
    4. Other procedures and resources that will increase public safety and prevent or mitigate a release of hazardous materials.

In general, every county or city and all facilities using a minimum amount of hazardous materials are required to formulate detailed contingency plans to eliminate, or at least minimize, the possibility and effect of fires, explosion, or spills. In conjunction with the California Office of Emergency Services, local jurisdictions have enacted ordinances that set standards for area and business emergency response plans. These requirements include immediate notification, mitigation of an actual or threatened release of a hazardous material, and evacuation of the emergency area.

VIII. g) Since the facilities that operate equipment subject to the requirements in PAR 1110.2 are located at existing industrial or commercial sites in urban areas where wildlands are not prevalent, risk of loss or injury associated with wildland fires is not expected. Accordingly, this impact issue will not be further evaluated in the Draft SEA.

Based upon these considerations, no significant adverse hazards and hazardous materials impacts are expected from the implementation of PAR 1110.2 and as such, the topic of hazards and hazardous materials impacts will not be further analyzed in the Draft SEA. Since no significant hazards and hazardous materials impacts were identified, no mitigation measures are necessary or required.

IX. HYDROLOGY AND WATER QUALITY.

Would the project:	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
a) Violate any water quality standards, waste discharge requirements, exceed wastewater treatment requirements of the applicable Regional Water Quality Control Board, or otherwise substantially degrade water quality?	☐	☐	☐	☑
b) Substantially deplete groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level (e.g. the production rate of pre-existing nearby wells would drop to a level which would not support existing land uses or planned uses for which permits have been granted)?	☐	☐	☐	☑
c) Substantially alter the existing drainage pattern of the site or area, including through alteration of the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner that would result in substantial erosion or siltation on- or off-site or flooding on- or off-site?	☐	☐	☐	☑
d) Create or contribute runoff water which would exceed the capacity of existing or planned storm water drainage systems or provide substantial additional sources of polluted runoff?	☐	☐	☐	☑
e) Place housing or other structures within a 100-year flood hazard area as mapped on a federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood hazard delineation map, which would impede or redirect flood flows?	☐	☐	☐	☑
f) Expose people or structures to a significant risk of loss, injury or death involving flooding, including flooding	☐	☐	☐	☑

Would the project:	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
as a result of the failure of a levee or dam, or inundation by seiche, tsunami, or mudflow?				
g) Require or result in the construction of new water or wastewater treatment facilities or new storm water drainage facilities, or expansion of existing facilities, the construction of which could cause significant environmental effects?	☐	☐	☐	☑
h) Have sufficient water supplies available to serve the project from existing entitlements and resources, or are new or expanded entitlements needed?	☐	☐	☐	☑
i) Result in a determination by the wastewater treatment provider which serves or may serve the project that it has adequate capacity to serve the project's projected demand in addition to the provider's existing commitments?	☐	☐	☐	☑

SIGNIFICANCE CRITERIA

Potential impacts on water resources will be considered significant if any of the following criteria apply:

<u>Water Demand:</u>

- The existing water supply does not have the capacity to meet the increased demands of the project, or the project would use more than 262,820 gallons per day of potable water.
- The project increases demand for total water by more than five million gallons per day.

<u>Water Quality:</u>

- The project will cause degradation or depletion of ground water resources substantially affecting current or future uses.
- The project will cause the degradation of surface water substantially affecting current or future uses.
- The project will result in a violation of National Pollutant Discharge Elimination System (NPDES) permit requirements.
- The capacities of existing or proposed wastewater treatment facilities and the sanitary sewer system are not sufficient to meet the needs of the project.
- The project results in substantial increases in the area of impervious surfaces, such that interference with groundwater recharge efforts occurs.
- The project results in alterations to the course or flow of floodwaters.

DISCUSSION

IX. a), g), & i) Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. The original analysis of the construction activities associated with construction at the biogas facilities is contained in the December 2007 Final EA. Therefore, no new physical changes requiring construction are involved with the proposed project. Complying with PAR 1110.2 will not change existing operations at affected facilities, nor would it result in an increased water demand that would cause a generation of increased volumes of wastewater. As a result, there are no potential changes in water demand or wastewater volume or composition expected from facilities complying with the requirements in PAR 1110.2. Further, PAR 1110.2 is not expected to cause affected facilities to violate any water quality standard or wastewater discharge requirements since there would be no water needed and no wastewater volumes generated as a result of implementing with PAR 1110.2. PAR 1110.2 is not expected to have any water demand or water quality impacts for the following reasons:

- The proposed project does not increase demand on the existing water supply.
- The proposed project does not increase demand for total water by more than 5,000,000 gallons per day.
- The proposed project does not increase demand for potable water by more than 262,820 gallons per day.
- The proposed project does not require construction of new water conveyance infrastructure.
- The proposed project does not create a substantial increase in mass inflow of effluents to public wastewater treatment facilities.
- The proposed project does not result in a substantial degradation of surface water or groundwater quality.
- The proposed project does not result in substantial increases in the area of impervious surfaces, such that interference with groundwater recharge efforts occurs.
- The proposed project does not result in alterations to the course or flow of floodwaters.

Lastly, PAR 1110.2 will not increase storm water discharge, since no major construction activities are expected at affected facilities. Further, no new areas at existing affected facilities are expected to be paved, so PAR 1110.2 will not increase storm water runoff during operation. Therefore, no new storm water discharge treatment facilities or modifications to existing facilities will be required due to the implementation of PAR 1110.2. Accordingly, PAR 1110.2 is not expected to generate any impacts relative to construction of new storm water drainage facilities.

IX. b) & h) Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. Therefore, no increase to any affected facilities' existing water demand is expected and implementation of PAR 1110.2 will not increase demand for, or otherwise affect groundwater supplies or interfere with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level. In addition, implementation of PAR 1110.2 will not increase demand for water from existing entitlements and resources, and will not require new or expanded entitlements. Since equipment affected by PAR 1110.2 generally occur in existing structures at existing facilities, no paving is required that might interfere with groundwater recharge. Therefore, no water demand impacts are expected as the result of implementing PAR 1110.2.

IX. c) & d) Implementation of PAR 1110.2 will occur at existing facilities that are typically located in industrial or commercial areas that are paved and already have drainage infrastructures in place. Since PAR 1110.2 does not involve major construction activities that would include activities such as site preparation, grading, et cetera, no changes to storm water runoff, drainage patterns, groundwater characteristics, or flow are expected. Therefore, these impact areas are not expected to be affected by PAR 1110.2.

IX. e) & f) The proposed project will not require construction of new housing, contribute to the construction of new building structures, or require modifications or changes to existing structures. Further, PAR 1110.2 is not expected to require additional workers at affected facilities. Therefore, PAR 1110.2 is not expected to generate construction of any new structures in 100-year flood areas as mapped on a federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood delineation map. As a result, PAR 1110.2 is not expected to expose people or structures to any new flooding risks, or make worse any existing flooding risks. Finally, PAR 1110.2 will not affect any potential flood hazards inundation by seiche, tsunami, or mud flow that may already exist relative to existing facilities or create new hazards at existing facilities.

Based upon these considerations, no hydrology and water quality impacts are expected from the implementation of PAR 1110.2 and as such, the topic of hydrology and water quality will not be further analyzed in the Draft SEA. Since no significant hydrology and water quality impacts were identified, no mitigation measures are necessary or required.

X. LAND USE AND PLANNING.

Would the project:	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
a) Physically divide an established community?	☐	☐	☐	☑
b) Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project (including, but not limited to the general plan, specific plan, local coastal program or zoning ordinance) adopted for the purpose of avoiding or mitigating an environmental effect?	☐	☐	☐	☑

SIGNIFICANCE CRITERIA

Land use and planning impacts will be considered significant if the project conflicts with the land use and zoning designations established by local jurisdictions.

DISCUSSION

X. a) & b) Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. Since PAR 1110.2 affects equipment operating at existing facilities, it does not include any components that would require physically dividing an established community.

There are no provisions in PAR 1110.2 that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by implementation of PAR 1110.2. Further, PAR 1110.2 would not affect in any way habitat conservation or natural community conservation plans, agricultural resources or operations, and would not create divisions in any existing communities. Therefore, present or planned land uses in the region will not be significantly adversely affected as a result of PAR 1110.2.

Based upon these considerations, no land use and planning impacts are expected from the implementation of PAR 1110.2 and as such, the topic of land use and planning will not be further analyzed in the Draft SEA. Since no significant land use and planning impacts were identified, no mitigation measures are necessary or required.

XI. MINERAL RESOURCES.

Would the project:	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
a) Result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state?	☐	☐	☐	☑
b) Result in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan?	☐	☐	☐	☑

SIGNIFICANCE CRITERIA

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

- The project would result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state.
- The proposed project results in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.

DISCUSSION

XI. a) & b) There are no provisions in PAR 1110.2 that would result in the loss of availability of a known mineral resource of value to the region and the residents of the state, or of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.

Based upon these aforementioned considerations, no significant mineral resources impacts are expected from the implementation of PAR 1110.2 and as such, the topic of mineral resources will not be further analyzed in the Draft SEA. Since no significant mineral resources impacts were identified, no mitigation measures are necessary or required.

XII. NOISE.

Would the project result in:	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
a) Exposure of persons to or generation of permanent noise levels in excess of standards established in the local general plan or noise ordinance, or applicable standards of other agencies?	☐	☐	☐	☑
b) Exposure of persons to or generation of excessive groundborne vibration or groundborne noise levels?	☐	☐	☐	☑
c) A substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project?	☐	☐	☐	☑
d) For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public use airport or private airstrip, would the project expose people residing or working in the project area to excessive noise levels?	☐	☐	☐	☑

SIGNIFICANCE CRITERIA

Impacts on noise will be considered significant if:

- Construction noise levels exceed the local noise ordinances or, if the noise threshold is currently exceeded, project noise sources increase ambient noise levels by more than three decibels (dBA) at the site boundary. Construction noise levels will be considered significant if they exceed federal Occupational Safety and Health Administration (OSHA) noise standards for workers.
- The proposed project operational noise levels exceed any of the local noise ordinances at the site boundary or, if the noise threshold is currently exceeded, project noise sources increase ambient noise levels by more than three dBA at the site boundary.

DISCUSSION

XII. a) Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. The original analysis of the construction activities associated with construction at the biogas facilities is contained in the December 2007 Final EA. Therefore, no new physical changes requiring construction are involved with the proposed project. Since implementation of PAR 1110.2 does not involve construction, no significant adverse noise impacts are anticipated.

No other physical modifications or changes associated with the implementation of PAR 1110.2 are expected. Thus, PAR 1110.2 is not expected to expose persons to the generation of excessive noise levels above current facility levels. It is expected that any facility affected by PAR 1110.2 will comply with all existing noise control laws or ordinances. Further, OSHA and CalOSHA have established noise standards to protect worker health. It is expected that all workers at affected facilities will continue complying with applicable noise standards.

XII. b) PAR 1110.2 is not anticipated to expose people to or generate excessive groundborne vibration or groundborne noise levels since no construction activities are expected to occur at the existing facilities and the affected equipment are not inherently noisy or create excessive vibrations.

XII. c) A permanent increase in ambient noise levels at the affected facilities above existing levels as a result of implementing the proposed project is unlikely to occur because no new equipment that would be installed as part of implementing PAR 1110.2. Therefore, the existing noise levels are unlikely to change and raise ambient noise levels in the vicinities of the existing facilities to above a level of significance in response to implementing PAR 1110.2.

XII. d) Implementation of PAR 1110.2 would not consist of improvements within the existing facilities that would require major construction activities. Even if an affected facility is located near a public/private airport, there are no new noise impacts expected from any of the existing facilities as a result of complying with the proposed project. Thus, PAR 1110.2 is not expected to expose people residing or working in the project vicinities to excessive noise levels. See also the response to item XII. a).

Based upon these considerations, no significant noise impacts are expected from the implementation of PAR 1110.2 and as such, the topic of noise is not further evaluated in the Draft SEA. Since no significant noise impacts were identified, no mitigation measures are necessary or required.

XIII. POPULATION AND HOUSING.

Would the project:	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
a) Induce substantial growth in an area either directly (for example, by proposing new homes and businesses) or indirectly (e.g. through extension of roads or other infrastructure)?	☐	☐	☐	☑
b) Displace substantial numbers of people or existing housing, necessitating the construction of replacement housing elsewhere?	☐	☐	☐	☑

SIGNIFICANCE CRITERIA

Impacts of the proposed project on population and housing will be considered significant if the following criteria are exceeded:

- The demand for temporary or permanent housing exceeds the existing supply.
- The proposed project produces additional population, housing or employment inconsistent with adopted plans either in terms of overall amount or location.

DISCUSSION

XIII. a) & b) Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. The original analysis of the construction activities associated with construction at the biogas facilities is contained in the December 2007 Final EA. Therefore, no new physical changes requiring construction are involved with the proposed project. Further, PAR 1110.2 is not anticipated to generate any significant effects, either direct or indirect, on the district's population or population distribution as no additional workers for equipment operation are anticipated to be required at facilities subject to the proposed amendments. Human population within the jurisdiction of the SCAQMD is anticipated to grow regardless of implementing PAR 1110.2. As such, PAR 1110.2 will not result in changes in population densities or induce significant growth in population.

Because PAR 1110.2 primarily affects existing facilities located mostly in industrial and commercial areas, PAR 1110.2 is not expected to result in the creation of any industry that would affect population growth, directly or indirectly induce the construction of single- or multiple-family units, or require the displacement of people elsewhere.

Based upon these considerations, significant population and housing impacts are not expected from the implementation of PAR 1110.2 and as such, the topic of population and housing will not be further evaluated in the Draft EA. Since no significant population and housing impacts were identified, no mitigation measures are necessary or required.

XIV. PUBLIC SERVICES.

Would the proposal result in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, need for new or physically altered government facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response times or other performance objectives for any of the following public services:	**Potentially Significant Impact**	**Less Than Significant With Mitigation**	**Less Than Significant Impact**	**No Impact**
a) Fire protection?	☐	☐	☐	☑
b) Police protection?	☐	☐	☐	☑
c) Schools?	☐	☐	☐	☑
d) Other public facilities?	☐	☐	☐	☑

SIGNIFICANCE CRITERIA

Impacts on public services will be considered significant if the project results in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, or the need for new or physically altered government facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response time or other performance objectives.

DISCUSSION

XIV. a) & b) Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. The original analysis of the construction activities associated with construction at the biogas facilities is contained in the December 2007 Final EA. Therefore, no new physical changes requiring construction are involved with the proposed project. No other physical modifications or changes associated with the implementation of PAR 1110.2 are expected. Therefore, PAR 1110.2 is not expected to change substantially or increase the chances for fires or explosions that could affect local fire departments or increase the need for security at affected facilities, which could adversely affect local police departments.

XIV. c) & d) The local labor pool (e.g., workforce) of particular affected facility areas is expected to remain the same since PAR 1110.2 would not trigger any changes to current facility operations. Therefore, with no increase in local population anticipated, no significant adverse impacts are expected to local schools.

Implementation of PAR 1110.2 would not result in the need for government services, new or physically altered public facilities in order to maintain acceptable service ratios, response times, or other performance objectives. There will be no increase in population and, therefore, no need for physically altered public facilities.

Based upon these considerations, no significant public services impacts are expected from implementing PAR 1110.2 and as such, the topic of public services will not be further evaluated in the Draft SEA. Since no significant public services impacts were identified, no mitigation measures are necessary or required.

XV. RECREATION.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
a) Would the project increase the use of existing neighborhood and regional parks or other recreational facilities such that substantial physical deterioration of the facility would occur or be accelerated?	☐	☐	☐	☑
b) Does the project include recreational facilities or require the construction or expansion of recreational facilities that might have an adverse physical effect on the environment or recreational services?	☐	☐	☐	☑

SIGNIFICANCE CRITERIA

Impacts to recreation will be considered significant if:

- The project results in an increased demand for neighborhood or regional parks or other recreational facilities.
- The project adversely affects existing recreational opportunities.

DISCUSSION

XV. a) & b) As previously discussed under the topic of "Land Use and Planning," there are no provisions in PAR 1110.2 that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by the changes proposed in PAR 1110.2. Further, PAR 1110.2 would not increase the demand for or use of existing neighborhood and regional parks or other recreational facilities or require the construction of new or expansion of existing recreational facilities that might have an adverse physical effect on the environment because it will not directly or indirectly increase or redistribute population.

Based upon these considerations, no significant recreation impacts are expected from implementing PAR 1110.2 and as such, the topic of recreation will not be further evaluated in the Draft SEA. Since no significant recreation impacts were identified, no mitigation measures are necessary or required.

XVI. SOLID/HAZARDOUS WASTE.

Would the project:	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
a) Be served by a landfill with sufficient permitted capacity to accommodate the project's solid waste disposal needs?	☐	☐	☐	☑
b) Comply with federal, state, and local statutes and regulations related to solid and hazardous waste?	☐	☐	☐	☑

SIGNIFICANCE CRITERIA

The proposed project impacts on solid/hazardous waste will be considered significant if the following occurs:

- The generation and disposal of hazardous and non-hazardous waste exceeds the capacity of designated landfills.

DISCUSSION

XVI. a) & b) Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. The original analysis of the construction activities associated with construction at the biogas facilities is contained in the December 2007 Final EA. Therefore, no new physical changes requiring construction are involved with the proposed project. No other physical modifications or changes associated with the implementation of PAR 1110.2 are expected. Because affected equipment has a finite lifetime, it will ultimately have to be replaced at the end of its useful life. However, affected equipment may also be refurbished and used elsewhere. In addition, any scrap metal from replaced units has economic value and is expected to be recycled, so any solid or hazardous waste impacts specifically associated with PAR 1110.2 are expected to be minor. As a result, no substantial change in the amount or character of solid or hazardous waste streams is expected to occur. For these reasons, PAR 1110.2 is not expected to increase the volume of solid or hazardous wastes from affected facilities, require additional waste disposal capacity, or generate waste that does not meet applicable local, state, or federal regulations.

Based upon these considerations, PAR 1110.2 is not expected to increase the volume of solid or hazardous wastes that cannot be handled by existing municipal or hazardous waste disposal facilities, or require additional waste disposal capacity. Further, implementing PAR 1110.2 is not expected to interfere with any affected facility's ability to comply with applicable local, state, or federal waste disposal regulations.

Thus, no significant solid/hazardous waste impacts are expected from implementing PAR 1110.2 and as such, the topic of solid/hazardous waste will not be further evaluated in the Draft SEA.

Since no significant solid/hazardous waste impacts were identified, no mitigation measures are necessary or required.

XVII. TRANSPORTATION/TRAFFIC.

Would the project:	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
a) Conflict with an applicable plan, ordinance or policy establishing measures of effectiveness for the performance of the circulation system, taking into account all modes of transportation including mass transit and non-motorized travel and relevant components of the circulation system, including but not limited to intersections, streets, highways and freeways, pedestrian and bicycle paths, and mass transit?	☐	☐	☐	☑
b) Conflict with an applicable congestion management program, including but not limited to level of service standards and travel demand measures, or other standards established by the county congestion management agency for designated roads or highways?	☐	☐	☐	☑
c) Result in a change in air traffic patterns, including either an increase in traffic levels or a change in location that results in substantial safety risks?	☐	☐	☐	☑
d) Substantially increase hazards due to a design feature (e.g. sharp curves or dangerous intersections) or incompatible uses (e.g. farm equipment)?	☐	☐	☐	☑
e) Result in inadequate emergency access?	☐	☐	☐	☑
f) Conflict with adopted policies, plans, or programs regarding public transit, bicycle, or pedestrian facilities, or otherwise decrease the performance or safety of such facilities?	☐	☐	☐	☑

SIGNIFICANCE CRITERIA

Impacts on transportation/traffic will be considered significant if any of the following criteria apply:

- Peak period levels on major arterials are disrupted to a point where level of service (LOS) is reduced to D, E or F for more than one month.
- An intersection's volume to capacity ratio increase by 0.02 (two percent) or more when the LOS is already D, E or F.
- A major roadway is closed to all through traffic, and no alternate route is available.
- The project conflicts with applicable policies, plans or programs establishing measures of effectiveness, thereby decreasing the performance or safety of any mode of transportation.
- There is an increase in traffic that is substantial in relation to the existing traffic load and capacity of the street system.
- The demand for parking facilities is substantially increased.
- Water borne, rail car or air traffic is substantially altered.
- Traffic hazards to motor vehicles, bicyclists or pedestrians are substantially increased.
- The need for more than 350 employees
- An increase in heavy-duty transport truck traffic to and/or from the facility by more than 350 truck round trips per day
- Increase customer traffic by more than 700 visits per day.

DISCUSSION

XVII. a) & b) Implementation of PAR 1110.2 would give owner/operators of biogas fueled engines, which are those operated at landfills and wastewater treatment plants, additional time to meet the emissions limits in the current rule, which would delay the emissions reductions from implementation of that technology. PAR 1110.2 would also place limits on the number of breakdown events and the emissions during the breakdown events, which would reduce the breakdown emissions currently being allowed for all engines. The original analysis of the construction activities associated with construction at the biogas facilities is contained in the December 2007 Final EA. Therefore, no new physical changes requiring construction are involved with the proposed project. PAR 1110.2 affects a large variety of combustion equipment operating primarily at existing facilities and has no potential to adversely affect transportation. PAR 1110.2 would have no affect on existing operations at the affected facilities that would change or cause additional transportation demands or services. Therefore, implementation of PAR 1110.2 is not expected to significantly adversely affect circulation patterns on local roadways or the level of service at intersections near affected facilities.

XVII. c) Compliance with PAR 1110.2 will not require operators of existing facilities to construct buildings or other structures that could interfere with flight patterns so the height and appearance of the existing structures are not expected to change. Therefore, implementation of PAR 1110.2 is not expected to adversely affect air traffic patterns. Further, PAR 1110.2 will not affect in any way air traffic in the region because it will not require transport of any materials by air.

XVII. d) & e) Since PAR 1110.2 will only affect combustion equipment primarily located at existing facilities in industrial or commercial areas, no offsite modifications to roadways are anticipated for the proposed project that would result in an additional design hazard or incompatible uses or changes to emergency access at or in the vicinity of the affected facilities. As a result, PAR 1110.2 is not expected to adversely impact emergency access.

XVII. f) No facility modifications or changes are expected as a result of implementation of PAR 1110.2 that would conflict with adopted policies, plans, or programs regarding public transit, bicycle, or pedestrian facilities, or otherwise decrease the performance or safety of such facilities.

Based upon these considerations, no significant adverse transportation/traffic impacts are expected from implementing PAR 1110.2 and as such, the topic of transportation/traffic will not be further evaluated in the Draft SEA. Since no significant transportation/traffic impacts were identified, no mitigation measures are necessary or required.

XVIII. MANDATORY FINDINGS OF SIGNIFICANCE.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
a) Does the project have the potential to degrade the quality of the environment, substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, reduce the number or restrict the range of a rare or endangered plant or animal or eliminate important examples of the major periods of California history or prehistory?	☐	☐	☐	☑
b) Does the project have impacts that are individually limited, but cumulatively considerable? ("Cumulatively considerable" means that the incremental effects of a project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects)	☑	☐	☐	☐
c) Does the project have environmental effects that will cause substantial adverse effects on human beings, either directly or indirectly?	☑	☐	☐	☐

DISCUSSION

XVIII. a) As discussed in the "Biological Resources" section, PAR 1110.2 is not expected to significantly adversely affect plant or animal species or the habitat on which they rely because the affected equipment is located at primarily existing facilities in industrial or commercial areas which have already been greatly disturbed and that currently do not support such habitats. Additionally, special status plants, animals, or natural communities are not expected to be found within close proximity to the facilities affected by PAR 1110.2.

XVIII. b) & c) As discussed in items I through XVIII above, the proposed project is not expected to create significant adverse impacts to any environmental area except for criteria air pollutants under the topic of air quality and GHGs. Potentially significant adverse criteria air pollutant impacts under the topics of air quality and GHG emissions will be analyzed in the Draft SEA.

APPENDIX A

PROPOSED AMENDED RULE 1110.2

(Adopted August 3, 1990)(Amended September 7, 1990)(Amended August 12, 1994)
(Amended December 9, 1994)(Amended November 14, 1997)
(Amended June 3, 2005)(Amended February 1, 2008)(Amended July 9, 2010)
(Amended September 7, 2012)(July 2015)

PROPOSED AMENDED RULE 1110.2 EMISSIONS FROM GASEOUS- AND LIQUID-FUELED ENGINES

(a) Purpose

The purpose of Rule 1110.2 is to reduce Oxides of Nitrogen (NO_x), Volatile Organic Compounds (VOCs), and Carbon Monoxide (CO) from engines.

(b) Applicability

All stationary and portable engines over 50 rated brake horsepower (bhp) are subject to this rule.

(c) Definitions

For the purpose of this rule, the following definitions shall apply:

(1) AGRICULTURAL STATIONARY ENGINE is a non-portable engine used for the growing and harvesting of crops or the raising of fowl or animals for the primary purpose of making a profit, providing a livelihood, or conducting agricultural research or instruction by an educational institution. An engine used for the processing or distribution of crops or fowl or animals is not an agricultural engine.

(2) APPROVED EMISSION CONTROL PLAN is a control plan, submitted on or before December 31, 1992, and approved by the Executive Officer prior to November 14, 1997, that was required by subdivision (d) of this rule as amended September 7, 1990.

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

(4~~3~~) CERTIFIED SPARK-IGNITION ENGINES mean engines certified by California Air Resources Board (CARB) to meet emission standards in accordance with Title 13, Chapter 9, Article 4.5 of the California Code of Regulations (CCR).

(5~~4~~) EMERGENCY STANDBY ENGINE is an engine which operates as a temporary replacement for primary mechanical or electrical power during periods of fuel or energy shortage or while the primary power supply is under repair.

(6~~5~~) ENGINE is any spark- or compression-ignited internal combustion engine, including engines used for control of VOCs, but not including engines used for self-propulsion.

(7~~6~~) EXEMPT COMPOUNDS are defined in District Rule 102 - Definition of Terms.

(8~~7~~) FACILITY means any source or group of sources or other air contaminant emitting activities which are located on one or more contiguous properties within the District, in actual physical contact or separated solely by a public roadway or other public right-of-way, and are owned or operated by the same person (or by persons under common control), or an outer continental shelf (OCS) source as determined in Section 55.2 of Title 40, Part 55 of the Code of Federal Regulations (40 CFR Part 55). Such above-described groups, if noncontiguous, but connected only by land carrying a pipeline, shall not be considered one facility. Sources or installations involved in crude oil and gas production in Southern California Coastal or OCS Waters and transport of such crude oil and gas in Southern California Coastal or OCS Waters shall be included in the same facility which is under the same ownership or use entitlement as the crude oil and gas production facility on-shore.

(9~~8~~) LEAN-BURN ENGINE means an engine that operates with high levels of excess air and an exhaust oxygen concentration of greater than 4 percent.

(10~~9~~) LOCATION means any single site at a building, structure, facility, or installation. For the purpose of this definition, a site is a space occupied or to be occupied by an engine. For engines which are brought to a facility to perform maintenance on equipment at its permanent or ordinary location, each maintenance site shall be a separate location.

(11~~0~~) NET ELECTRICAL ENERGY means the electrical energy produced by a generator, less the electrical energy consumed by any auxiliary equipment necessary to operate the engine generator and, if applicable, any heat recovery equipment, such as heat exchangers.

(12~~1~~) NON-ROAD ENGINE is any engine, defined under 40 CFR Part 89, that does not remain or will not remain at a location for more than 12 consecutive months, or a shorter period of time where such period is representative of normal annual source operation at a stationary source that resides at a fixed location for more than 12 months (e.g., seasonal operations such as canning facilities), and meets one of the following:

(A) Is used in or on a piece of equipment that is self-propelled or serves a dual purpose by both propelling itself and performing another function (such as a mobile crane); or

(B) Is used in or on a piece of equipment that is intended to be propelled while performing its function (such as lawn mowers and string trimmers); or

(C) By itself, or in or on a piece of equipment, is portable or transportable, meaning designed to be and capable of being carried or moved from one location to another. Transportability includes, but is not limited to, wheels, skids, carrying handles, dolly, trailer, platform or mounting.

(13~~2~~) OPERATING CYCLE means a period of time within which a round of regularly recurring events is completed, and cannot be stopped without the risk of endangering public safety or health, causing material damage to the equipment or product, or cannot be stopped due to technical constraints. Economic reasons alone will not be sufficient to extend this time period. The operating cycle includes batch processes that may start and finish several times within a twenty-four hour period, in which case each start to finish interval is considered a complete cycle.

(14~~3~~) OXIDES OF NITROGEN (NOx) means nitric oxide and nitrogen dioxide.

(15~~4~~) PORTABLE ENGINE is an engine that, by itself or in or on a piece of equipment, is designed to be and capable of being carried or moved from one location to another. Indications of portability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, platform or mounting. The operator must demonstrate the necessity of the engine being periodically moved from one location to another because of the nature of the operation.

An engine is not portable if:

(A) the engine or its replacement remains or will reside at the same location for more than 12 consecutive months. Any engine, such as a back-up or stand-by engine, that replaces an engine at a location and is intended to perform the same function as the engine being replaced, will be included in calculating the consecutive time period. In that case, the cumulative time of both engines, including the time between the removal of the original engine and installation of the replacement engine, will be counted toward the consecutive time period; or

(B) the engine remains or will reside at a location for less than 12 consecutive months where such a period represents the full length of normal annual source operations such as a seasonal source; or

(C) the engine is removed from one location for a period and then it or its equivalent is returned to the same location thereby circumventing the portable engine residence time requirements.

The period during which the engine is maintained at a designated storage facility shall be excluded from the residency time determination.

(16~~5~~) RATED BRAKE HORSEPOWER (bhp) is the rating specified by the manufacturer, without regard to any derating, and listed on the engine nameplate.

(17~~6~~) RICH-BURN ENGINE WITH A THREE-WAY CATALYST means an engine designed to operate near stoichiometric conditions with a catalytic control device that simultaneously reduces emissions of NOx, CO and VOC.

(18~~7~~) STATIONARY ENGINE is an engine which is either attached to a foundation or if not so attached, does not meet the definition of a portable or non-road engine and is not a motor vehicle as defined in Section 415 of the California Vehicle Code.

(19~~8~~) TIER 2 AND TIER 3 DIESEL ENGINES mean engines certified by CARB to meet Tier 2 or Tier 3 emission standards in accordance with Title 13, Chapter 9, Article 4 of the CCR.

(20~~19~~) USEFUL HEAT RECOVERED means the waste heat recovered from the engine exhaust and/or cooling system that is put to productive use. The waste heat recovered may be assumed to be 100% useful unless the hot water, steam or other medium is vented to the atmosphere, or sent directly to a cooling tower or other unproductive use.

(21~~0~~) VOLATILE ORGANIC COMPOUND (VOC) is as defined in Rule 102.

(d) Requirements

(1) Stationary Engines:

(A) Operators of stationary engines with an amended Rule 1110.1 Emission Control Plan submitted by July 1, 1991, or an Approved Emission Control Plan, designating the permanent removal of engines or the replacement of engines with electric motors, in accordance with subparagraph (d)(1)(B), shall do so by December 31, 1999, or not operate the engines on or after December 31, 1999 in a manner that exceeds the emission concentration limits listed in Table I:

TABLE I ALTERNATIVE TO ELECTRIFICATION CONCENTRATION LIMITS		
NO_x	VOC	CO
(ppmvd)[1] 11	(ppmvd)[2] 30	(ppmvd)[1] 70

[1] Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

[2] Parts per million by volume, measured as carbon**,** corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

(B) The operator of any stationary engine not covered by (d)(1)(A) and not exempt from this rule shall

(i) Remove such engine permanently from service or replace the engine with an electric motor, or

(ii) Not operate the engine in a manner that exceeds the applicable emission concentration limits listed in either Table II or Table III-A or B.

TABLE II CONCENTRATION LIMITS		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 36 bhp < 500: 45	250	2000
CONCENTRATION LIMITS EFFECTIVE JULY 1, 2010		

NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 11 bhp < 500: 45	bhp ≥ 500: 30 bhp < 500: 250	bhp ≥ 500: 250 bhp < 500: 2000

CONCENTRATION LIMITS EFFECTIVE JULY 1, 2011		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250

1 Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

2 Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

The concentration limits effective on and after July 1, 2010 shall not apply to engines that operate less than 500 hours per year or use less than 1 x 10^9 British Thermal Units (Btus) per year (higher heating value) of fuel.

If the operator of a two-stroke engine equipped with an oxidation catalyst and insulated exhaust ducts and catalyst housing demonstrates that the CO and VOC limits effective on and after July 1, 2010 are not achievable, then the Executive Officer may, with United States Environmental Protection Agency (EPA) approval, establish technologically achievable, case-by-case CO and VOC limits in place of the concentration limits effective on and after July 1, 2010. The case-by-case limits shall not exceed 250 ppmvd VOC and 2000 ppmvd CO.

If the operator of an engine that uses non-pipeline quality natural gas demonstrates that due to the varying heating value of the gas a longer averaging time is necessary, the Executive Officer may establish for the engine a longer averaging time, not to exceed six hours, for any of the concentration limits of Table II. Non-pipeline quality natural gas is a gas that does not meet the gas specifications of the local gas utility and is not supplied to the local gas utility.

(C) The operator of any stationary engine fired by landfill or digester gas (biogas) shall not operate the engine in a manner that exceeds the emission concentration limits of Table III-A, provided that the facility monthly average biogas usage by the biogas engines is 90% or more, based on the higher heating value of the fuels used. The calculation of the monthly facility biogas use percentage may exclude natural gas fired during: any electrical outage at the facility; a Stage 2 or higher electrical emergencies called by the California Independent System Operator Corporation; and when a sewage treatment plant activates an Emergency Operations Center or Incident Command System, as part of an emergency response plan, because of either high influent flows caused by precipitation or a disaster.

TABLE III-A CONCENTRATION LIMITS FOR LANDFILL AND DIGESTER GAS (BIOGAS)-FIRED ENGINES		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 36 x ECF[3] bhp < 500: 45 x ECF[3]	Landfill Gas: 40 Digester Gas: 250 x ECF[3]	2000
TABLE III-B CONCENTRATION LIMITS EFFECTIVE JANUARY 1, 2017~~6~~		
NOx (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250

1 Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

2 Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

3 ECF is the efficiency correction factor.

The ECF shall be 1.0 unless:

(i) The engine operator has measured the engine's net specific energy consumption (q_a), in compliance with ASME

Performance Test Code PTC 17 -1973, at the average load of the engine; and

(ii) The ECF-corrected emission limit is made a condition of the engine's permit to operate.

The ECF is as follows:

$$ECF = \frac{9250 \text{ Btus/hp-hr}}{\text{Measured } q_a \text{ in Btus/hp-hr}}$$

Measured q_a shall be based on the lower heating value of the fuel. ECF shall not be less than 1.0.

The Executive Officer may approve the burning of more than 10% natural gas in a landfill or digester gas-fired engine, when it is necessary, if: the only alternative to limiting natural gas to 10% would be shutting down the engine and flaring more landfill or digester gas; or the engine requires more natural gas in order for a waste heat recovery boiler to provide enough thermal energy to operate a sewage treatment plant, and other boilers at the facility are unable to provide the necessary thermal energy.

(D) Notwithstanding the provisions of subparagraph (d)(1)(B), the operator of any stationary engine fired by landfill or digester gas (biogas) shall not operate the engine in a manner that exceeds the emission concentration limits of Table III.

(E) Biogas engine operators that establish to the satisfaction of the Executive Officer that they have complied with the emissions limits of Table III-B by January 1, 2015 will have their respective engine permit application fees refunded.

(F) For the City of San Bernardino and Eastern Municipal Water District that commenced and implemented technology demonstration projects prior to January 1, 2015, all their biogas engines shall have until January 1, 2018 to comply with the requirements of Table III-B.

(~~F~~G) Once an engine complies with the concentration limits as specified in Table III-B, there shall be no limit on the percentage of natural gas burned.

(~~G~~H) The concentration limits effective as specified in Table III-B shall not apply to engines that operate fewer than 500 hours per year or use less than 1 x 10^9 Btus per year (higher heating value) of fuel.

(~~H~~I) An operator of a biogas engine may determine compliance with the NOx and/or CO limits of Table III-B by utilizing a longer averaging time as set forth below, provided the operator demonstrates through CEMS data that the engine is achieving a concentration at or below 9.9 ppmv for NOx and 225 ppmv for CO (if CO is elected for averaging), each corrected to 15% O_2, over a 4 month time period. An operator may utilize a monthly fixed interval averaging time for the first 4 months of the retrofitted engine's operation and up to a 24 hour fixed interval averaging time thereafter. For purposes of determining compliance using a longer averaging time:

(i) An operator shall not average data during one-minute periods in which the underlying equipment is not operated or when the CEMS is undergoing zero or calibration checks, cylinder gas audits, or routine maintenance in accordance with the provisions in Rules 218 and 218.1.

(ii) Notwithstanding the requirements of Rules 218 and 218.1, for one-minute time periods where NOx and/or CO CEMS data are greater than 95 percent of the Rule 218.1 Full Scale Range while the underlying equipment is operating, an operator shall use substitute data. A concentration equivalent to 3 times the NOx and/or CO emission limits in Table III-B (each corrected to 15% O2) shall be used as substitute data.

(iii) The intentional shutdown of a CEMS to circumvent the emission limits of Table III-B while the underlying equipment is in operation shall constitute a violation of this rule.

(iv) The averaging provisions of this subparagraph shall not apply to CEMS that are time shared by multiple biogas engines.

(J~~I~~) The operator of any new engine subject to subparagraph (e)(1)(B) shall:

(i) Comply with the requirements of Best Available Control Technology in accordance with Regulation XIII if the engine requires a District permit; or

(ii) Not operate the engine in a manner that exceeds the emission concentration limits in Table I if the engine does not require a District permit.

(K~~J~~) By February 1, 2009, the operator of a spark-ignited engine without a Rule 218-approved continuous emission monitoring system (CEMS) or a Regulation XX (RECLAIM)-approved CEMS shall equip and maintain the engine with an air-to-fuel ratio controller with an oxygen sensor and feedback control, or other equivalent technology approved by the Executive Officer, CARB and EPA.

(L~~K~~) New Non-Emergency Electrical Generators

(i) All new non-emergency engines driving electrical-generators shall comply with the following emission standards:

TABLE IV
EMISSION STANDARDS FOR NEW ELECTRICAL GENERATION ENGINES

Pollutant	Emission Standard (lbs/MW-hr)[1]
NOx	0.070
CO	0.20
VOC	0.10[2]

1. The averaging time of the emission standards is 15 minutes for NOx and CO and the sampling time required by the test method for VOC, except as described in the following clause.
2. Mass emissions of VOC shall be calculated using a ratio of 16.04 pounds of VOC per lb-mole of carbon.

(ii) Engines subject to this subparagraph that produce combined heat and electrical power may include one megawatt-hour (MW-hr) for each 3.4 million Btus of useful heat recovered (MW_{th}-hr), in addition to each MW-hr of net electricity produced (MW_e-hr). The compliance of such engines shall be based on the following equation:

$$\frac{Lbs}{MW\text{-}hr} = \frac{Lbs}{MW_e\text{-}hr} \times \text{Electrical Energy Factor (EEF)}$$

Where:

Lbs/MW-hr = The calculated emissions that shall comply with the emission standards in Table IV

Lbs/MW_e-hr = The short-term engine emission limit in pounds per MW_e-hr of net electrical energy produced, averaged over 15 minutes. The engine shall comply with this limit at all times.

EEF = The annual MW_e-hrs of net electrical energy produced divided by the sum of annual MW_e-hrs plus annual MW_{th}-hrs of useful heat recovered. The engine operator shall demonstrate annually that the EEF is less than the value required for compliance.

(iii) For combined heat and power engines, the short-term emission limits in lbs/MW_e-hr and the maximum allowed annual EEF must be selected by operator and stated on the operating permit.

(iv) Notwithstanding Rule 2001, the requirements of this subparagraph shall apply to NOx emissions from new non-emergency engines driving electrical-generators subject to Regulation XX (RECLAIM).

(v) This subparagraph does not apply to: engines installed prior to February 1, 2008; engines issued a permit to construct prior to February 1, 2008 and installed within 12 months of the date of the permit to construct; engines for which an application is deemed complete by October 1, 2007; engines installed by an electric utility on Santa Catalina Island; engines installed at remote locations without access to natural gas and electric power; engines used to supply electrical power to ocean-going vessels while at berth, prior to January 1, 2014; or landfill or digester gas-fired engines that meet the requirements of subparagraph (d)(1)(C).

(2) Portable Engines:

(A) The operator of any portable engine generator subject to this rule shall not use the portable generator for:

(i) Power production into the electric grid, except to maintain grid stability during an emergency event or other unforeseen event that affects grid stability; or

(ii) Primary or supplemental power to a building, facility, stationary source, or stationary equipment, except during unforeseen interruptions of electrical power from the serving utility, maintenance and repair operations, and remote operations where grid power is unavailable. For interruptions of electrical power, the operation of a portable generator shall not exceed the time of the actual interruption of power.

This subparagraph shall not apply to a portable generator that complies with emission concentration limits of Table I and the other requirements in this rule applicable to stationary engines.

(B) The operator of any portable diesel engine shall comply with the applicable requirements of the Subchapter 7.5 Airborne Toxic Control Measures for diesel particulate matter in Chapter 1, Division 3, Title 17 of the California Code of Regulations.

(C) The operator of any portable spark-ignited engine shall comply with the applicable requirements of the Large Spark Ignition Engine Fleet Requirements, Article 2, Chapter 15, Division 3, Title 13 of the California Code of Regulations.

(e) Compliance

(1) Agricultural Stationary Engines:

(A) The operator of any agricultural stationary engine subject to this rule and installed or issued a permit to construct prior to June 3, 2005 shall comply with subparagraph (d)(1)(B) and the other applicable provisions of this rule in accordance with the compliance schedules in Table V:

TABLE V COMPLIANCE SCHEDULES FOR STATIONARY AGRICULTURAL ENGINES		
Action Required	**Tier 2 and Tier 3 Diesel Engines, Certified Spark-Ignition Engines, and All Engines at Facilities with Actual Emissions Less Than the Amounts in the Table of Rule 219(q)**	**Other Engines**
Submit notification of applicability to the Executive Officer	January 1, 2006	January 1, 2006
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	March 1, 2009	September 1, 2007
Initiate construction of engine modifications, control equipment, or replacement engines	September 30, 2009, or 30 days after the permit to construct is issued, whichever is later	March 30, 2008, or 30 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	January 1, 2010, or 60 days after the permit to construct is issued, whichever is later	July 1, 2008, or 60 days after the permit to construct is issued, whichever is later
Complete initial source testing	March 1, 2010, or 120 days after the permit to construct is issued, whichever is later	September 1, 2008, or 120 days after the permit to construct is issued, whichever is later

The notification of applicability shall include the following for each engine:

(i) Name and mailing address of the operator

(ii) Address of the engine location

(iii) Manufacturer, model, serial number, and date of manufacture of the engine

(iv) Application number

(v) Engine type (diesel, rich-burn spark-ignition or lean-burn spark-ignition)

(vi) Engine fuel type

(vii) Engine use (pump, compressor, generator, or other)

(viii) Expected means of compliance (engine replacement, control equipment installation, or electrification)

(B) The operator of any new agricultural stationary engine that is not subject to the compliance schedule of subparagraph (e)(1)(A) for existing engines shall comply with the requirements of subparagraph (d)(1)(I) immediately upon installation.

(2) Non-Agricultural Stationary Engines:

(A) The operator of any stationary engine not meeting the requirements of subparagraphs (d)(1)(B) or (d)(1)(C) that go into effect in 2010 or later, shall comply with the compliance schedule in Table VI:

TABLE VI
COMPLIANCE SCHEDULE FOR NON -AGRICULTURAL STATIONARY ENGINES

Action Required	Applicable Compliance Date
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	Twelve months before the final compliance date
Initiate construction of engine modifications, control equipment, or replacement engines	Three months before the final compliance date, or 60 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	The final compliance date, or 120 days after the permit to construct is issued, whichever is later
Complete initial source	60 days after the final

TABLE VI COMPLIANCE SCHEDULE FOR NON -AGRICULTURAL STATIONARY ENGINES	
Action Required	**Applicable Compliance Date**
testing	compliance date in (d)(1)(B) or (d)(1)(C), or 180 days after the permit to construct is issued, whichever is later

(B) The operator of any stationary engine that elects to amend a permit to operate to incorporate ECF-adjusted emission limits shall submit to the Executive Officer an application for a change of permit conditions by August 1, 2008, and comply with emission limits of the previous version of this rule until February 1, 2009 when the engine shall be in compliance with the emission limits of this rule.

(C) The operator of any stationary engine that is required to add operating restrictions to a permit to operate to meet the requirements of this rule shall submit to the Executive Officer an application for a change of permit conditions by August 1, 2008.

(3) Stationary Engine CEMS

(A) The operator of any stationary engine with an existing CEMS shall commence the reporting required by Rule 218 Subdivision (f) on January 1, 2008. The first summary report for the six months ending June 30, 2008 shall be due on July 30, 2008.

(B) The operator of any stationary engine that is required to modify an existing CEMS or install a CEMS on an existing engine shall comply with the compliance schedule in Table VII. Public agencies shall be allowed one year more than the dates in Table VII, except for biogas engines.

TABLE VII
COMPLIANCE SCHEDULE FOR NEW OR MODIFIED CEMS
ON EXISTING ENGINES

	Applicable Compliance Dates For:		
Action Required	**Non-Biogas Engines Rated at 750 bhp or More**	**Non-Biogas Engines Rated at Less than 750 bhp**	**Biogas Engines***
Submit to the Executive Officer applications for new or modified CEMS	August 1, 2008	August 1, 2009	January 1, 2011
Complete installation and commence CEMS operation, calibration, and reporting requirements	Within 180 days of initial approval	Within 180 days of initial approval	Within 180 days of initial approval
Complete certification tests	Within 90 days of installation	Within 90 days of installation	Within 90 days of installation

TABLE VII
COMPLIANCE SCHEDULE FOR NEW OR MODIFIED CEMS
ON EXISTING ENGINES

	Applicable Compliance Dates For:		
Action Required	**Non-Biogas Engines Rated at 750 bhp or More**	**Non-Biogas Engines Rated at Less than 750 bhp**	**Biogas Engines***
Submit certification reports to Executive Officer	Within 45 days after tests are completed	Within 45 days after tests are completed	Within 45 days after tests are completed
Obtain final approval of CEMS	Within 1 year of initial approval	Within 1 year of initial approval	Within 1 year of initial approval

* A biogas engine is one that is subject to the emission limits of Table III.

(4) Stationary Engine Inspection and Monitoring (I&M) Plans:
The operator of stationary engines subject to the I&M plan provisions of subparagraph (f)(1)(D) shall:

(A) By August 1, 2008, submit an initial I&M plan application to the Executive Officer for approval;

(B) By December 1, 2008, implement an approved I&M plan or the I&M plan as submitted if the plan is not yet approved.

Any operator of 15 or more stationary engines subject to the I&M plan provisions shall comply with the above schedule for at least 50% of engines, and for the remaining engines shall:

(C) By February 1, 2009, submit an initial I&M plan application to the Executive Officer for approval;

(D) By June 1, 2009, implement an approved I&M plan or the I&M plan as submitted if the plan is not yet approved.

(5) Stationary Engine Air-to-Fuel Ratio Controllers

(A) The operator of any stationary engine that does not have an air-to-fuel ratio controller, as required by subparagraph (d)(1)(J), shall comply with those requirements in accordance with the compliance schedule in Table V, except that the application due date is no later than May 1, 2008 and the initial source testing may be conducted at the time of the testing required by subparagraph (f)(1)(C).

(B) The operator of any stationary engine that has the air-to-fuel ratio controller required by subparagraph (d)(1)(J), but it is not listed on the permit to operate, shall submit to the Executive Officer an application to amend the permit by April 1, 2008.

(C) The operator of more than five engines that do not have air-to-fuel ratio controllers may take an additional three months, to May 1, 2009, to install the equipment on up to 50% of the affected engines.

(6) New Stationary Engines

The operator of any new stationary engine issued a permit to construct after February 1, 2008 shall comply with the applicable I&M or CEMS requirements of this rule when operation commences. If applicable, the operator shall provide the required information in subparagraph (f)(1)(D) to the Executive Officer prior to the issuance of the permit to construct so that the I&M procedures can be included in the permit. A separate I&M plan application is not required.

(7) Biogas Engines

For any biogas engine for which the operator applies to the Executive Officer by April 1, 2008 for a change of permit conditions for ECF-corrected emission limits, or the approval to burn more than 10 percent natural gas in accordance with subparagraph (d)(1)(C), the biogas engine shall not be subject to the initial concentration limits of Tables II or III until August 1, 2008, provided the operator continues to comply with all emission limits in effect prior to February 1, 2008.

(8) Compliance Schedule Exception

If an engine operator submits to the Executive Officer an application for an administrative change of permit conditions to add a permit condition that causes the engine permit to expire by the effective date of any requirement of this rule, then the operator is not required to comply with the earlier steps required by this subdivision for that requirement. The effective date for the CEMS requirements shall be one year after the date that a CEMS application is due.

(9) Exceedance of Usage Limits

(A) If an engine was initially exempt from the new concentration limits in subparagraph (d)(1)(B) or subparagraph (d)(1)(C) that take effect on or after July 1, 2010 because of low engine use but later exceeds the low-use criteria, the operator shall bring the engine into compliance with the rule in accordance with the schedule in Table VI with the final compliance date in Table VI being twelve months after the conclusion of the first twelve-month period for which the engine exceeds the low-use criteria.

(B) If engines that were initially exempt from new CEMS by the low-use criterion in subclause (f)(1)(A)(ii)(I) later exceed that criterion, the operator shall install CEMS on those engines in accordance with the schedule in Table VII, except that the date for submitting the CEMS application in Table VII shall be six months after the conclusion of the first twelve-month period for which the engines exceed the criterion.

(f) Monitoring, Testing, Recordkeeping and Reporting

(1) Stationary engines:

The operator of any engine subject to the provisions of paragraph (d)(1) of this rule shall meet the following requirements:

(A) Continuous Emission Monitoring

(i) For engines of 1000 bhp and greater and operating more than two million bhp-hr per calendar year, a NO_x and CO continuous emission monitoring system (CEMS) shall be installed, operated and maintained in calibration to demonstrate compliance with the emission limits of this rule.

(ii) (I) For facilities with engines subject to paragraph (d)(1), having a combined rating of 1500 bhp or greater at the same location, and having a combined fuel usage of more than 16 x 10^9 Btus per year (higher heating value), CEMS shall be installed, operated and maintained in calibration to demonstrate compliance of those engines with the applicable NO_x and CO emission limits of this rule.

(II) Any engine that as of October 1, 2007 is located within 75 feet of another engine (measured from engine block to engine block) is considered to be at the same location. Operators of new engines shall not install engines farther than 75 feet from another engine unless the operator demonstrates to the Executive Officer that operational needs or space limitations require it.

(III) The following engines shall not be counted toward the combined rating or required to have a CEMS by this clause: engines rated at less than 500 bhp; standby engines that are limited by permit conditions to only operate when other primary engines are not operable; engines that are limited by permit conditions to operate less than 1000 hours per year or a fuel usage of less than 8 x 10^9 Btus per year (higher heating value of all fuels used); engines that are used primarily to fuel public natural gas transit vehicles and that are required by a permit condition to be irreversibly removed from service by December 31, 2014; and engines required to have a CEMS by the previous clause. A CEMS shall not be required if permit conditions limit the simultaneous use of the engines at the same location in a manner to limit the combined rating of all engines in simultaneous operation to less than 1500 bhp.

(IV) For engines rated below 1000 bhp, the CEMS may be time shared by multiple engines.

(V) Operation of engines by the electric utility in the Big Bear Lake area during the failure of a transmission line to the utility may be excluded from an hours-per-year or fuel usage limit that is elected by the operator pursuant to subclause (f)(1)(A)(ii)(III).

(VI) In lieu of complying with subclause (f)(1)(A)(ii)(I), an operator that is a public agency, or is contracted to operate engines solely for a public agency, may comply with the Inspection and Monitoring Plan requirements of subparagraph (f)(1)(D), except that the operator shall conduct emission checks at least weekly or every 150 operating hours, whichever occurs later. If any such engine is found to exceed an applicable NOx or CO limit by a source test required by subparagraph (f)(1)(C) or District test using a portable analyzer on three or more occasions in any 12-month period, the operator shall comply with the CEMS requirements of this subparagraph for such engine in accordance with the compliance schedule of Table VII, except that the operator shall submit a CEMS application to the Executive Officer within six months of the third exceedance.

(iii) All CEMS required by this rule shall:

(I) Comply with the applicable requirements of Rule 218 and 218.1, including equipment specifications and certification, operating, recordkeeping, quality assurance and reporting requirements, except as otherwise authorized by this rule;

(II) Include equipment that measures and records exhaust gas concentrations, both uncorrected and corrected to 15 percent oxygen on a dry basis; and

(III) Have data gathering and retrieval capability approved by the Executive Officer

(iv) The operator of an engine that is required to install CEMS may request the Executive Officer to approve an alternative monitoring device (or system components) to demonstrate compliance with the emission limits of this rule. The applicant shall demonstrate to the Executive Officer that the proposed alternative monitoring device is at a minimum equivalent in relative accuracy, precision, reliability, and timeliness to a CEMS for that engine, according to the criteria specified in 40 CFR Part 75 Subpart E. In lieu of the criteria specified in 40 CFR Part 75 Subpart E, substitute criteria is acceptable if the applicant demonstrates to the Executive Officer that the proposed alternative monitoring device is at minimum equivalent in relative accuracy, precision, reliability, and timeliness to a CEMS for that engine. Upon approval by the Executive Officer, the substitute criteria shall be submitted to EPA as an amendment to the State Implementation Plan (SIP).

If the alternative monitoring device is denied or fails to be recertified, a CEMS shall be required.

(v) Notwithstanding the requirements of Rules 218 and 218.1, operators of engines that are required to install a CEMS by clause (f)(1)(A)(ii) of this subparagraph may:

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

(II) Conduct relative accuracy testing on the same schedule for source testing in clause (f)(1)(C)(i), instead of annually. The minimum sampling time for each test is 15 minutes.

(vi) Notwithstanding the requirements of Rules 218 and 218.1, operators of engines that are required to install a CEMS by clause (ii) of this subparagraph, and that are to be monitored by a timeshared CEMS, may:

(I) Monitor an engine with the CEMS for 15 consecutive minutes, purge for the minimum required purge time, then monitor the next engine for 15 consecutive minutes. The CEMS shall operate continuously in this manner, except for required calibrations.

(II) Record the corrected and uncorrected NOx, CO and diluent data at least once per minute and calculate and record the 15-minute average corrected concentrations for each sampling period.

(III) Have sample lines to each engine that are not the same length. The purge time will be based on the sample line with the longest response time. Response times shall be checked during cylinder gas audits. Sample lines shall not exceed 100 feet in length.

(IV) Conduct a minimum of five tests for each engine during relative accuracy tests.

(V) Perform a cylinder gas audit every calendar quarter on each engine, except for engines for which relative accuracy testing was conducted that quarter.

(VI) Exclude monitoring of nitrogen dioxide (NO_2) for rich-burn engines, unless source testing demonstrates that NO_2 is more than 10 percent of total NOx.

(VII) Conduct daily calibration error (CE) tests by injecting calibration gases at the analyzers, except that at least once per week the CE test shall be conducted by injecting calibration gases as close to the probe tip as practical.

(VIII) Stop operating and calibrating the CEMs during any period that the operator has a continuous record that the engine was not in operation.

(vii) A CO CEMS shall not be required for lean-burn engines or an engine that is subject to Regulation XX (RECLAIM), and not required to have a NOx CEMS by that regulation.

(viii) Notwithstanding the requirements of this paragraph and paragraph (c)(2) of Rule 2012, an operator may take an existing NOx CEMS out of service for up to two weeks (cumulative) in order to modify the CEMS to add CO monitoring.

(B) Elapsed Time Meter

Maintain an operational non-resettable totalizing time meter to determine the engine elapsed operating time.

(C) Source Testing

(i) Effective August 1, 2008, conduct source testing for NO_x, VOC reported as carbon, and CO concentrations (concentrations in ppm by volume, corrected to 15 percent oxygen on dry basis) at least once every two years, or every 8,760 operating hours, whichever occurs first. Relative accuracy tests required by Rule 218.1 or 40 CFR Part 75 Subpart E will satisfy this requirement for those pollutants monitored by a CEMS. The source test frequency may be reduced to once every three years if the engine has operated less than 2,000 hours since the last source test. If the engine has not been operated within three months of the date a source test is required, the source test shall be conducted when the engine resumes operation for a period longer than either seven consecutive days or 15 cumulative days of operation. The operator of the engine shall keep sufficient operating records to demonstrate that it meets the requirements for extension of the source testing deadlines.

(ii) Conduct source testing for at least 30 minutes during normal operation (actual duty cycle). This test shall not be conducted under a steady-state condition unless it is the normal operation. In addition, conduct source testing for NOx and CO emissions for at least 15 minutes at: an engine's actual peak load, or the maximum load that can be practically achieved during the test, and; at actual minimum load, excluding idle, or the minimum load that can be practically achieved during the test. These additional two tests are not required if the permit limits the engine to operating at one defined load, ± 10%. No pre-tests for compliance are permitted. The emission test shall be conducted at least 40 operating hours, or at least 1 week, after any engine servicing or tuning. If an emission exceedance is found during any of the three phases of the test, that phase shall be completed and reported. The operator shall correct the exceedance, and the source test may be immediately resumed.

(iii) Use a contractor to conduct the source testing that is approved by the Executive Officer under the Laboratory Approval Program for the necessary test methods.

(iv) Submit a source test protocol to the Executive Officer for written approval at least 60 days before the scheduled date of the test. The source test protocol shall include the name, address and phone number of the engine operator and a District-approved source testing contractor that will conduct the test, the application and permit number(s), emission limits, a description of the engine(s) to be tested, the test methods and procedures to be used, the number of tests to be conducted and under what loads, the required minimum sampling time for the VOC test, based on the analytical detection limit and expected VOC levels, and a description of the parameters to be measured in accordance with the I&M plan required by subparagraph (f)(1)(D). The source test protocol shall be approved by the Executive Officer prior to any testing. The operator is not required to submit a protocol for approval if: there is a previously approved protocol that meets these requirements; the engine has not been altered in a manner that requires a permit alteration; and emission limits have not changed since the previous test. If the operator submits the protocol by the required date, and the Executive Officer takes longer than 60 days to approve the protocol, the operator shall be allowed the additional time needed to conduct the test.

(v) Provide the Executive Officer at least 30 days prior notice of any source test to afford the Executive Officer the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the engine operator shall notify the Executive Officer as soon as possible of any delay in the original test date, either by providing at least seven days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Executive Officer by mutual agreement.

(vi) Submit all source test reports, including a description of the equipment tested, to the Executive Officer within 60 days of completion of the test.

(vii) By February 1, 2009, provide, or cause to be provided, source testing facilities as follows:

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

(II) Safe sampling platform(s), scaffolding or mechanical lifts, including safe access, that comply with California General Safety Orders. Agricultural stationary engines are excused from this subclause if they are in remote locations without electrical power;

(III) Utilities for sampling and testing equipment. Agricultural stationary engines are exempt from this subclause if they are on wheels and moved to storage during the off season.

(D) Inspection and Monitoring (I&M) Plan

Submit to the Executive Officer for written approval and implement an I&M plan. One plan application is required for each facility. The I&M plan shall include:

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

(I) Procedures for using a portable NOx, CO and oxygen analyzer to establish the set points of the air-to-fuel ratio controller (AFRC) at 25%, 60% and 95% load (or fuel flow rate), ± 5%, or the minimum, midpoint and maximum loads that actually occur during normal operation, ± 5%, or at any one load within the ± 10% range that an engine permit is limited to in accordance with clause (f)(1)(C)(ii);

(II) Procedures for verifying that the AFRC is controlling the engine to the set point during the daily monitoring required by clause (f)(1)(D)(iv);

(III) Procedures for reestablishing all AFRC set points with a portable NOx, CO and oxygen analyzer whenever a set point must be readjusted, within 24 hours of an oxygen sensor replacement, and, for rich-burn engines with three way catalysts, between 100 and 150 engine operating hours after an oxygen sensor replacement;

(IV) For engines with catalysts, the maximum allowed exhaust temperature at the catalyst inlet, based on catalyst manufacturer specifications;

(V) For lean-burn engines with selective catalytic control devices, the minimum exhaust temperature at the catalyst inlet required for reactant flow (ammonia or urea), and procedures for using a portable NOx and oxygen analyzer to establish the acceptable range of reactant flow rate, as a function of load.

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

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

(iii) Procedures for at least weekly or every 150 engine operating hours, whichever occurs later, emissions checks by a portable NOx, CO and oxygen analyzer.

(I) If an engine is in compliance for three consecutive emission checks, without any adjustments to the oxygen sensor set points, then the engine may be checked monthly or every 750 engine operating hours, whichever occurs later, until there is a noncompliant emission check or, for rich-burn engines with three-way catalysts, the oxygen sensor is replaced. When making adjustments to the oxygen sensor set points, returning to a more frequent emission check schedule is not required if the engine is in compliance with the applicable emission limits prior to and after the set point adjustments, notwithstanding the requirements of (f)(1)(D)(iii)(IV).

(II) For diesel engines and other lean-burn engines that are subject to Regulation XX or have a NOx CEMs, and that are subject to a CO limit more stringent than the 2000 ppmvd limit of Tables II or III, a CO emission check shall be performed at least quarterly, or every 2,000 engine operating hours, whichever occurs later.

(III) For diesel engines and other lean-burn engines that are subject to Regulation XX or have a NOx CEMs, and that are not subject to a CO limit more stringent than the 2000 ppmvd limit of Tables II or III, emission checks are not required.

(IV) No engine or control system maintenance or tuning may be conducted within 72 hours prior to the emission check, unless it is an unscheduled, required repair.

(V) The portable analyzer shall be calibrated, maintained and operated in accordance with the manufacturer's specifications and recommendations and the Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Stationary Engines Subject to South Coast Air Quality Management District Rule 1110.2, approved on February 1, 2008, or subsequent protocol approved by EPA and the Executive Officer.

(iv) Procedures for at least daily monitoring, inspection and recordkeeping of:

(I) engine load or fuel flow rate;

(II) the set points, maximums and acceptable ranges of the parameters identified by clause (f)(1)(D)(i), and the actual values of the same parameters;

(III) the engine elapsed time meter operating hours;

(IV) the operating hours since the last emission check required by clause (f)(1)(D)(iii);

(V) for rich-burn engines with three-way catalysts, the difference of the exhaust temperatures (ΔT) at the inlet and outlet of the catalyst (changes in the ΔT can indicate changes in the effectiveness of the catalyst);

(VI) engine control system and AFRC system faults or alarms that affect emissions.

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

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

(I) For a breakdown resulting in a violation of this rule or a permit condition, or for a~~n~~ diagnostic emission check that finds emissions in excess of those allowed by this rule or a permit condition, the operator shall correct the problem and demonstrate compliance with a~~n~~ diagnostic emission check, or shut down an engine by the end of an operating cycle, or within 24 hours from the time the operator knew of the breakdown or excess emissions, or reasonably should have known, whichever is sooner.

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

(III) For a diagnostic emission check that detects NOx emissions (corrected to 15% O_2) greater than 11 ppmvd, but less than or equal to 20 ppmvd or CO emissions (corrected to 15% O_2) greater than 250 ppmvd, but less than or equal to 500 ppmvd (or from the permitted level up to 500 ppmvd), the operator shall comply with the requirements of subclause (f)(1)(D)(v)(I).

~~(II)~~(IV) For excess emissions due to breakdowns that result in NOx emissions (corrected to 15% O_2) greater than 20 ppmvd, but less than or equal to 45 ppmvd or CO emissions (corrected to 15% O_2) greater than 500 ppmvd, but less than or equal to 1000 ppmvd, the operator shall comply with the requirements of subclause (f)(1)(D)(v)(I) and (V).

(V) An operator shall not be considered in violation of the emission limits ~~of~~ related to this rule ~~or permit conditions~~ if the operator complies with this clause (v)~~subparagraph~~ ~~and~~ ,the reporting requirements of subparagraph (f)(1)(H), and for each engine no more than three incidences of breakdowns resulting in excess emissions as referenced in the previous subclause in any calendar quarter. Notwithstanding this subclause (f)(1)(D)(v)(V), ~~A~~any diagnostic emission check conducted by District staff that finds excess emissions will be treated as ~~is~~ a violation.

~~(III)~~(VI) Excess emissions resulting from breakdowns that exceed 45 ppmv of NOx and 1000 ppmv of CO, each corrected to 15% O_2, will be treated as a violation.

(vi) Procedures and schedules for preventive and corrective maintenance.

(vii) Procedures for reporting noncompliance to the Executive Officer in accordance with subparagraph (f)(1)(H).

(viii) Procedures and format for the recordkeeping of monitoring and other actions required by the plan.

(ix) Procedures for plan revisions. Before any change in I&M plan operations can be implemented, the revised I&M plan shall be submitted to and approved by the Executive Officer. The operator shall apply for a plan revision prior to any change in emission limits or control equipment.

(x) An engine is not subject to this subparagraph (f)(1)(D) if it is required by this rule to have a NOx and CO CEMS, or voluntarily has a NOx and CO CEMS that complies with this rule.

~~(x)~~(xi) If an engine has a NOx CEMS and does not have a CO CEMS, it is not subject to this subparagraph (f)(1)(D) as it pertains to NOx only.

(E) Operating Log

Maintain a monthly engine operating log that includes:

(i) Total hours of operation;

(ii) Type of liquid and/or type of gaseous fuel;

(iii) Fuel consumption (cubic feet of gas and gallons of liquid); and

(iv) Cumulative hours of operation since the last source test required in subparagraph (f)(1)(C).

Facilities subject to Regulation XX may maintain a quarterly log for engines that are designated as a process unit on the facility permit.

(F) New Non-Emergency Electrical Generating Engines

Operators of engines subject to the requirements of subparagraph (d)(1)(K) shall also meet the following requirements.

(i) The engine generator shall be monitored with a calibrated electric meter that measures the net electrical output of the engine generator system, which is the difference between the electrical output of the generator and the electricity consumed by the auxiliary equipment necessary to operate the engine generator.

(ii) For engines monitored with a CEMS, the emissions of the monitored pollutants in ppmvd corrected to 15% O2, lbs/hr, and lbs/MW_e-hr and the net MW_e-hrs produced shall be calculated and recorded for the four 15-minute periods of each hour of operation. The mass emissions of NOx shall be calculated based on the measured fuel flow and one of the F factor methods of 40 CFR 60, Appendix A, Method 19, or other method approved by the Executive Officer. Mass emissions of CO shall be calculated in the same manner as NOx, except that the ppmvd CO shall be converted to lb/scf using a conversion factor of 0.727×10^{-7}.

(iii) For NOx and CO emissions from engines not monitored with a CEMS and VOC emissions from all engines, the emissions of NOx, CO and VOC in lbs/MW_e-hr shall be calculated and recorded whenever the pollutant is measured by a source test or emission check. Mass emissions of NOx and CO shall be calculated in the same manner as the previous clause. Mass emissions of VOC shall be calculated in the same manner, except that the ppmvd VOC as carbon shall be converted to lb/scf using a conversion factor of 0.415×10^{-7}.

(iv) For engines generating combined heat and power that rely on the EEF to comply with Table IV emission standards, the daily and annual useful heat recovered (MW_{th}-hrs), net electrical energy generated (MW_e-hrs) and EEF shall be monitored and recorded.

(v) Other methods of calculating mass emissions than those specified, such as by direct measurement of exhaust volume, may be used if approved by the Executive Officer. All monitoring, calculation, and recordkeeping procedures must be approved by the Executive Officer.

(vi) Operators of combined heat and power engines shall submit to the Executive Officer the reports of the following information within 15 days of the end of the first year of operation, and thereafter within 15 days of the end of each calendar year: the annual net electrical energy generated (MW_e-hrs); the annual useful heat recovered (MW_{th}-hrs), the annual EEF calculated in accordance with clause (d)(1)(K)(ii); and the maximum annual EEF allowed by the operating permit. If the actual annual EEF exceeds the allowed EEF, the report shall also include the time periods and emissions for all instances where emissions exceeded any emission standard in Table IV.

(G) Portable Analyzer Operator Training

The portable analyzer tests required by the I&M Plan requirements of subparagraph (f)(1)(D) shall only be conducted by a person who has completed an appropriate District-approved training program in the operation of portable analyzers and has received a certification issued by the District.

(H) Reporting Requirements

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

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

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

(II) The duration of the breakdown;

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

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

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

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

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

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

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

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

(2) Portable engines:

The operator of any portable engine shall maintain a monthly engine operating log that includes:

(i) Total hours of operation; or

(ii) Type of liquid and/or type of gaseous fuel; and

(iii) Fuel consumption (cubic feet of gas and gallons of liquid).

Facilities subject to Regulation XX may maintain a quarterly log for engines that are designated as a process unit on the facility permit.

(3) Recordkeeping for All Engines

All data, logs, test reports and other information required by this rule shall be maintained for at least five years and made available for inspection by the Executive Officer.

(g) Test Methods

Testing to verify compliance with the applicable requirements shall be conducted in accordance with the test methods specified in Table VIII, or any test methods approved by CARB and EPA, and authorized by the Executive Officer.

TABLE VIII

TESTING METHODS

Pollutant	Method
NO_x	District Method 100.1
CO	District Method 100.1

TABLE VIII

TESTING METHODS

Pollutant	Method
VOC	District Method 25.1* or District Method 25.3*

* Excluding ethane and methane

A violation of any standard of this rule established by any of the specified test methods, or any test methods approved by the CARB or EPA, and authorized by the Executive Officer, shall constitute a violation of this rule.

(h) Alternate Compliance Option

(1) In lieu of complying with the applicable emission limits by the effective date specified in Table III-B or subparagraph (d)(1)(F), owners or operators of biogas-fired units may elect to defer compliance in quarterly increments up to one additional year, provided the owner or operator: ~~In lieu of complying with the applicable emission limits by the effective date specified in Table III-B, owners or operators of biogas-fired units that operate under long term fixed price power purchase agreements that have been entered into prior to February 1, 2008 and extend beyond January 1, 2016 may elect to defer compliance by up to two years and no later than January 1, 2018, provided the owner or operator:~~

(A) Submits an alternate compliance plan and pays a Compliance Flexibility Fee, as provided for in paragraph (h)(2), to the Executive Officer at least ~~15~~60 days prior to the applicable compliance date in Table III-B, or subparagraph (d)(1)(F) for biogas technology demonstration project engines, and

(B) Maintains on-site a copy of verification of Compliance Flexibility Fee payment and AQMD approval of the alternate compliance plan that shall be made available upon request to AQMD staff.

(2) Plan Submittal

The alternate compliance plan submitted pursuant to paragraph (h)(1) shall include:

(A) A completed AQMD Form 400A with company name, AQMD Facility ID, identification that application is for a compliance plan (Section 7a of form), and identification that request is for Rule 1110.2 Compliance Flexibility Fee option (Section 9 of form);

(B) Attached documentation of unit permit ID, unit rated brake horsepower (bhp), and fee calculation;

~~(C) Proof that the power purchase agreement was entered into prior to February 1, 2008 and extends beyond January 1, 2016.~~

(C~~D~~) Filing Fee payment; and

(D~~E~~) Compliance Flexibility Fee payment as calculated by the following equation:

CFF = bhp x R x Q~~Y~~

Where,

CFF = Compliance Flexibility Fee, $

bhp = rated brake horsepower of unit

R = Fee Rate = $11.75~~47~~ per brake horsepower per quarter~~year~~

Q~~Y~~ = Number of quarters~~years~~ (up to four~~up to 2 years for engines required to comply by January 1, 2016~~)

(3) Usage of Compliance Flexibility Fee funds

The funds collected from the Compliance Flexibility Fee will be applied to AQMD NOx reduction programs pursuant to protocols approved under District rules.

(i) Exemptions

The provisions of subdivision (d) shall not apply to:

(1) All orchard wind machines powered by an internal combustion engine.

(2) Emergency standby engines, engines used for fire-fighting and flood control, and any other emergency engines approved by the Executive Officer, which have permit conditions that limit operation to 200 hours or less per year as determined by an elapsed operating time meter, and agricultural emergency standby engines that are exempt from a District

permit and operate 200 hours or less per year as determined by an elapsed operating time meter.

(3) Laboratory engines used in research and testing purposes.

(4) Engines operated for purposes of performance verification and testing of engines.

(5) Auxiliary engines used to power other engines or gas turbines during start-ups.

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

(7) Nonroad engines, with the exception that subparagraph (d)(2)(A) shall apply to portable generators.

(8) Engines operating on San Clemente Island; and engines operated by the County of Riverside for the purpose of public safety communication at Santa Rosa Peak in Riverside County, where the site is located at an elevation of higher than 7,400 feet above sea level and is without access to electric power and natural gas.

(9) Agricultural stationary engines provided that:

(A) The operator submits documentation to the Executive Officer by the applicable date in Table V when permit applications are due that the applicable electric utility has rejected an application for an electrical line extension to the location of the engines, or the Executive Officer determines that the operator does not qualify, due to no fault of the operator, for funding authorized by California Health and Safety Code Section 44229; and

(B) The operator replaces the engines, in accordance with the compliance schedule of Table ~~I~~X, with engines certified by CARB to meet the Tier 4 emission standards of 40 CFR Part 1039 Section 1039.101, Table 1. These Tier 4 replacement engines shall be considered to comply with Best Available Control Technology; and

(C) The operator does not operate the Tier 4 engines in a manner that exceeds the not-to-exceed standards of 40 CFR Section 1039.101, Paragraph (e), as determined by the test methods of subdivision (g) of this rule.

TABLE IX
COMPLIANCE SCHEDULE FOR INSTALLATION OF NEW TIER 4 STATIONARY AGRICULTURAL ENGINES

Action Required	Due Date
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	March 1, 2013
Initiate construction of engine modifications, control equipment, or replacement engines	September 30, 2013, or 30 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	January 1, 2014, or 60 days after the permit to construct is issued, whichever is later
Complete initial source testing	March 1, 2014, or 120 days after the permit to construct is issued, whichever is later

(10) An engine start-up, until sufficient operating temperatures are reached for proper operation of the emission control equipment, and an engine shutdown period. The periods shall not exceed 30 minutes, unless the Executive Officer approves a longer period not exceeding 2 hours for an engine and makes it a condition of the engine permit.

(11) An engine start-up, after an engine overhaul or major repair requiring removal of a cylinder head, for a period not to exceed four operating hours.

(12) The initial commissioning of a new engine for a period specified by permit conditions, provided the operator takes measures to reduce emissions and the duration of the commissioning to the extent possible. The commissioning period shall not exceed 150 operating hours.