California Environmental Protection Agency
AIR RESOURCES BOARD

Air Quality Guidance for Siting Biorefineries in California

Stationary Source Division
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DRAFT

State of California
California Environmental Protection Agency
Air Resources Board

Air Quality Guidance for Siting Biorefineries in California

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Table of Contents

Page

Acronyms and Abbreviations

AB 2588	Air Toxics "Hot Spots" Program
AB 32	Assembly Bill 32, California Global Warming Solutions Act of 2006
AIP	achieved in practice (as it relates to BACT)
ARB	California Air Resources Board
ASTM	American Society for Testing and Materials
ATC	Authority to Construct
ATCM	air toxic control measure
avg	average
BAAQMD	Bay Area Air Quality Management District
BACT	best available control technology
BARCT	best available retrofit control technology
bhp	brake horsepower
CAA	Clean Air Act
CAPCOA	California Air Pollution Control Officer Association
CEC	California Energy Commission
CFB	circulating fluidized-bed
CH_4	methane
CHP	combined heat and power
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
DDGS	distillers dried grains and solubles
DEIR	draft environmental impact report
DG	distributed generation
district	air pollution control or air quality management district
dscf	dry standard cubic foot
EF	emission factor
ERC	emission reduction credit
ESP	electrostatic precipitator
FGR	flue gas recirculation
FT	Fischer-Tropsch
GHG	greenhouse gas
gr	grain
GVWR	gross vehicle weight rating
H_2S	hydrogen sulfide
Handbook	ARB's Air Quality and Land Use Handbook
HC	hydrocarbon
hp	horsepower
hr	hour
HRA	health risk assessment
IC engine	internal combustion engine
kW	kilowatt
lb	pound
lb/day	pounds per day

Acronyms and Abbreviations (cont.)

lb/hr	pounds per hour
lb/MMBtu	pounds per million British Thermal Units
lb/MWh	pounds per megawatt hour
LAER	lowest achievable emission rate
LNB	low NO_x burner
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LSI	large spark-ignition
MDEP	Massachusetts Department of Environmental Protection
MMBtu/hr	million British Thermal Units per hour
MW	megawatt
N_2	nitrogen
NACAA	National Association of Clean Air Agencies
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	ammonia
NH_4	ammonium
NO_x	oxides of nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	oxygen
Plan	AB 32 Scoping Plan
PM	particulate matter
PM_{10}	particulate matter 10 micrometers in diameter and smaller
ppm	parts per million
ppmv	parts per million by volume
ppmvd	parts per million, by volume, dry
PSD	prevention of significant deterioration
RACT	reasonably available control technique
Report	Air Quality Guidance Document for Siting Biorefineries
SCAQMD	South Coast Air Quality Management District
scf	standard cubic foot
scfm	standard cubic foot per minute
SCR	selective catalytic reduction
SIP	State Implementation Plan
SJVAPCD	San Joaquin Valley Air Pollution Control District
SMAQMD	Sacramento Metropolitan Air Quality Management District
SNCR	selective non-catalytic reduction
SOV	single occupancy vehicle
SO_x	oxides of sulfur
SWCV	solid waste collection vehicle
TAC	toxic air contaminant
tech. feas.	technically feasible
VMT	vehicle miles travelled

Acronyms and Abbreviations (cont.)

VOC	volatile organic compound
Working group	Air Quality Guidance Document for Siting Biorefineries Working group

Terminology

Anaerobic Digestion: A bacterial decomposition process that operates in the absence of oxygen.

Bagasse: The dry, fibrous residue remaining after the extraction of juice from the crushed stalks of sugar crops.

Baghouse: An air pollution control device that traps particulate matter by forcing gas streams through fabric filter bags.

Best available control technology (BACT): BACT is determined for each emissions unit and is the most stringent emission level that:

- Has been achieved in practice for a given class or category of source, or
- Is contained in any implementation plan approved by the United States Environmental Protection Agency, or
- Is any more stringent control technique determined to be both technologically feasible and cost effective.

Best available retrofit control technology (BARCT): Defined in California Health and Safety Code, section 40406 as "an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."

Biodiesel: A fuel comprised of mono-alkyl esters of long chain fatty acids derived from vegetable oils or animal fats, designated B100, and meeting the requirements of the American Society for Testing and Materials standard (ASTM) D6751-07b.

Biogas: Gas produced by the anaerobic digestion of animal manure, food and yard waste, dedicated energy crops, organic material in landfills, and/or biosolids. The term biogas is also used in this Report to refer to gas produced by anaerobic digestion that has not been treated to remove impurities and has a unknown methane content.

Biofuel: Liquid, solid, or gaseous fuel produced from biomass feedstocks.

Biomass: Material of recent biological origin that can be converted to energy and other marketable products.

Biomethane: Gas produced by anaerobic digestion that has been treated to remove most constituents except methane.

Biorefinery: A facility that converts biomass to fuels, heat, electricity, and chemicals.

Biosolids: Organic material resulting from the treatment of sewage sludge or wastewater.

Terminology (cont.)

Cellulose: A long chain of sugar molecules that provides strength to the primary cell wall of green plants. Bacteria can convert cellulose to ethanol.

Compost: An organic material derived from the aerobic decomposition of plant and animal matter.

Compressed natural gas (CNG): A natural gas that has been compressed to a pressure greater than ambient pressure.

Ethanol: A two carbon produced from biomass, such as corn, sugarcane, sugar beets, or cellulosic material.

Fermentation: The anaerobic enzymatic conversion of carbohydrates, to alcohol, carbon dioxide, and water.

Fischer-Tropsch process: A catalyzed chemical reaction in which synthesis gas is converted into liquid hydrocarbons.

Gasification: The thermal decomposition of organic matter at high temperatures in a controlled oxygen atmosphere to produce a synthesis gas primarily comprised of carbon monoxide (CO), hydrogen, CO_2, and solid residues.

Glycerin: A liquid by-product of biodiesel production used in the manufacture of cosmetics, liquid soaps, inks, and lubricants.

Heating value: The amount of energy available from burning a given amount of biomass.

Hydrolysis: A chemical process in which a molecule is cleaved into two parts by the addition of a molecule of water.

Liquefied natural gas (LNG): A natural gas that has been pressurized and cooled so as to liquefy it for use as a vehicle fuel.

Lowest achievable emission rate (LAER): The most stringent emission limitation contained in the implementation plan of any state or achieved in practice for a class or category of source. It is a term from the federal New Source Review program and is required on major new or modified stationary sources in nonattainment areas.

Pyrolysis: A process similar to gasification, but often uses external heating without oxygen. It is usually optimized for production of liquid fuels that can be used directly or further refined for use as engine fuels, chemicals, and/or adhesives.

Terminology (cont.)

Regenerative thermal oxidizer (RTO): An emission control strategy that uses high temperature thermal oxidation to convert VOCs to CO_2 and water.

Renewable diesel: A mixture of hydrocarbons derived from renewable non-petroleum sources, and meeting the requirements of ASTM D975. Renewable diesel is traditionally made from hydrotreatment of triglycerides.

Selective catalytic reduction (SCR): A post-combustion control technology that selectively reduces NO_x emissions by combining ammonia and oxygen with NO_x in the exhaust gas in the presence of a catalyst to form molecular nitrogen (N_2) and water.

Sewage sludge: The solids separated during the treatment of municipal wastewater.

Sodium methoxide: A base catalyst used in the production of biodiesel.

Synthesis gas (syngas): A combustible gas mixture containing varying amounts of CO, CO_2, and hydrogen that is produced by the gasification of organic matter.

EXECUTIVE SUMMARY

Introduction

The Air Resources Board (ARB or Board) approved the adoption of the Low Carbon Fuel Standard (LCFS) in April 2009. The LCFS is designed to reduce California's dependence on petroleum; create a market for clean transportation technology; and stimulate the production and use of alternative, low-carbon fuels in California. The LCFS will reduce greenhouse gas (GHG) emissions by reducing the carbon intensity of transportation fuels used in California by an average of 10 percent by the year 2020. The regulation establishes performance standards that fuel producers and importers must meet each year beginning in 2011.

The LCFS Resolution 09-31(see Appendix A) directed the ARB Executive Officer to work with local air districts, regulated parties, environmental and public health groups, and other stakeholders to develop a best practices guidance document for use by stakeholders when they are assessing and mitigating the air emissions associated with biofuel production facilities in California.

This section summarizes the contents of this Air Quality Guidance Document for Siting Biorefineries (Report) in question-and-answer format.

1. What is the purpose of this Report?

This Report responds to the LCFS Resolution 09-31, which directed the ARB Executive Officer to develop a best practices guidance document for use by stakeholders when they are considering the siting of biofuel production facilities in California. As indicated in the LCFS Initial Statement of Reasons, ARB staff determined that the implementation of the LCFS regulation would create a potential for additional biorefineries to be built in California. This Report identifies the most current stringent limits for air emissions from individual pieces of stationary process equipment, and provides general guidance on available options for mitigating mobile source emissions associated with biorefineries.

2. How is this Report organized?

The Executive Summary summarizes the requirements for and the contents of this Report. Chapter I provides a description of the biofuel production conversion technologies addressed by this Report. Chapter II provides a list of existing biorefineries in California. Chapter III provides an overview of air quality regulatory requirements for stationary sources in California. Chapter IV provides an overview of the stationary sources and their emissions associated with each conversion technology addressed by this Report. Chapter V summarizes the emissions data gathered from engineering evaluations, air district permits, Best Available Control Technology (BACT) analyses, and California Environmental Quality Act (CEQA) analyses for the conversion technologies addressed by this Report. Chapter VI provides a summary of the most current stringent emission limits identified for process equipment used at biorefineries.

Chapter VII provides an overview of the air quality regulatory requirements for mobile sources. Chapter VIII provides an overview of the mobile source emissions associated with biorefineries. Chapter IX provides an overview of the available options to mitigate mobile source emissions associated with biorefineries. Chapter X discusses future updates and activities related to this Report.

3. How should this Report be used?

This Report was developed to assist air quality agencies, local land use planners, environmental and public health groups, project proponents, and other stakeholders conducting air quality evaluations for new or expanding biorefineries. Stakeholders may also find this Report useful during site selection, air quality permitting, and identification of potential CEQA mitigation measures. This document can also assist stakeholders in evaluating the relative air quality impacts of the various conversion technology options that are available for the biofuels addressed by this Report.

This Report should be used in combination with other air quality information, such as air quality attainment status, progress in achieving commitments contained in State Implementation Plans (SIP), site-specific modeling, availability of potential emissions mitigation measures, proximity to sensitive land uses, local health risk management policies, and availability of potential mobile source mitigation measures.

This Report can be used as a starting point in conducting air quality evaluations, but is not intended to substitute for the case-by-case permitting decisions conducted by local air quality, environmental, or planning agencies.

This Report is not intended to establish new BACT, identify best available retrofit control technology (BARCT) emissions levels, or verify emission levels claimed to be achievable by vendors of conversion technologies. BACT is determined on a case-by-case basis to account for advancements in technology and processes. In addition, this Report is not intended to pre-empt, replace, or devalue the decision-making processes that are associated with the outcomes of transportation planning analyses, site specific air quality modeling, risk assessments, SIP modeling, or future rules and regulations adopted for the purpose of controlling emissions of criteria pollutants, toxic air contaminants (TAC), or GHGs.

4. How was this Report developed?

ARB staff solicited volunteers and formed a working group with representation from the local air pollution control and air quality management districts (district); biorefinery and waste management industries; and environmental and public health groups (see Appendix B for a list of working group members and their affiliations). Beginning in August 2009, the working group met by teleconference 11 times to discuss the drafting of this Report. In addition, ARB staff held public workshops (August 2009 and January 2010) that included an update on progress and discussion of this Report.

ARB staff conducted a nationwide call for information about existing or planned biorefineries through the National Association of Clean Air Agencies (NACAA), and four of California's 35 districts. ARB staff compiled the most current stringent emission limits identified for process equipment used at biorefineries, and options available to mitigate mobile source emissions associated with biorefineries through review of:

- Adopted and proposed district rules;
- Control techniques required as BACT or Lowest Achievable Emission Rate (LAER);
- Emission levels achieved in practice, as verified by test results; and
- More stringent control techniques which are technologically and economically feasible, but are not yet achieved in practice.
- Business, Transportation, and Housing and the California Environmental Protection Agency's Goods Movement Action Plan (2007);
- California Air Pollution Control Officers Association's Health Risk Assessment for Proposed Land Use Projects (2009);
- California Air Resources Board's Air Quality and Land Use Handbook: A Community Health Perspective (2005);
- State and local CEQA guidelines; and
- Draft and final Environmental Impact Reports (EIR) for various industrial facilities.

ARB staff intends to distribute a draft version of this Report to the LCFS listserve at ARB, and the Bioenergy listserve at the California Energy Commission (CEC) for public review. ARB staff also intends to conduct a publicly-noticed meeting prior to a 45-day review period. After considering the comments, ARB staff intend to prepare a final version of this report no later than February 2011.

5. Which biofuels and conversion technologies are evaluated in this Report?

ARB staff evaluated the following biofuels: ethanol from grains, sugarcane and cellulose; biodiesel; renewable diesel; biogas; hydrogen; and biogasoline. ARB staff evaluated the following commercially available conversion technologies: fermentation, hydrolysis, gasification, transesterification, anaerobic digestion, reformation, and acid fermentation.

6. Which pollutants are addressed in this Report?

This Report addresses the following pollutants from stationary and mobile sources associated with biorefineries: oxides of nitrogen (NO_x), particulate matter (PM), volatile organic compounds (VOC), oxides of sulfur (SO_x), carbon monoxide (CO), TACs, and GHGs.

7. How are GHGs addressed by this Report?

This Report does not intend to preempt the development process for strategies and measures associated with the California Global Warming Solutions Act of 2006, also known as Assembly Bill 32 (AB 32). ARB is currently developing a number of broad and specific strategies to reduce GHGs from both stationary and mobile sources. However, many of the mitigation strategies provided in this Report will provide GHG reductions by promoting overall efficiency in energy conversion technologies and encouraging the recovery of energy and other marketable products from biomass feedstocks. Implementation of the mitigation strategies for both stationary and mobile sources will allow users of electricity, heat, and liquid and gaseous fuels to reduce GHGs, partially offset their reliance upon fossil fuels, and preserve efforts to achieve and maintain federal and state ambient air quality standards and to reduce TAC emissions.

8. What are the most stringent emission limits identified for process equipment at biorefineries?

Table ES-1 summarizes the most current stringent emission limits identified by ARB staff for process equipment that might be used at biorefineries. The alternate limits listed under certain equipment categories in Table ES-1 were identified by ARB staff as being the most current stringent emission limit for an individual air pollutant contained in a rule, regulation, guidance document, BACT analysis, or permit. In the case of biomethane-fueled fuel cells, the alternate limits are the future emission standards that will be required by statewide regulation as of January 1, 2013. Data collected by ARB staff indicates the 2013 standards may be achievable now, and therefore, ARB staff recommend that regulatory agencies evaluate the feasibility of the alternate limit for an individual project. For the other equipment categories, ARB staff did not have sufficient data at the drafting of this Report to determine whether the alternate limit is achievable in conjunction with the other corresponding most current stringent emission limits identified for the class/category of source. In these cases, ARB staff also recommend that regulatory agencies evaluate the feasibility of the alternate limit for an individual project.

Table ES-1. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries

Class/Category of Source	NO_x	CO	VOC	SO_x	PM10
Grain receiving, conveying, and grinding operations					Emission limit corresponding to use of a baghouse with 99% control, or equivalent
Methanol / Sodium Methoxide receiving and storage			Emission limit corresponding to use of a VOC		

Class/Category of Source	NO_x	CO	VOC	SO_x	PM10
			control system capable of 99.5% or better control efficiency		
Fermentation process: yeast, liquefaction, beerwell, and process condensate tanks			Emission limit corresponding to use of a VOC control system capable of 99.5% or better control efficiency		
Distillation and wet cake processes			Emission limit corresponding to use of a VOC control system (wet scrubber or equivalent) capable of 95% or better control efficiency		
Natural gas-fired boiler, ≥2 to <5 MMBtu/hr	Non-atmospheric units: 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu) Atmospheric units: 12 ppmvd @ 3% O_2 (0.015 lb/MMBtu)	Firetube type: 50 ppmvd @ 3% O_2 Watertube type: 100 ppmvd @ 3% O_2	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf
Natural gas-fired boiler, ≥5 to <20 MMBtu/hr	6 ppmvd @ 3% O_2 (0.007 lb/MMBtu)	Firetube type: ≤50 ppmvd @ 3% O_2 Watertube type: ≤100 ppmvd @ 3% O_2	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf
Natural gas-fired boiler, ≥20 MMBtu/hr	5 ppmvd @ 3% O_2 (0.0062 lb/MMBtu)	Firetube type: ≤50 ppmvd @ 3% O_2 Watertube type: ≤100 ppmvd @ 3% O_2 ——— For units ≥250 MMBtu/hr[1]: 10 ppmvd @ 3% O_2	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf

[1] This CO limit may be required for boilers rated at <250 MMBtu/hr if an oxidation catalyst is found to be cost effective, is necessary to meet toxic best available control technology, or for VOC emission control.

Class/Category of Source	NOx	CO	VOC	SO_x	PM10
Pumps and compressor seals			No leak of methane greater than 100 ppm above background and inspection and maintenance program		
Valves, flanges, and other types of connectors			No leak of methane greater than 100 ppm above background and inspection and maintenance program		
Wet cooling tower					Emission limit corresponding to use of a drift eliminator with 0.0005% drift loss
Natural gas-fired dryer	0.018 lb/MMBtu (15 ppmv @ 3% O_2)	0.07 lb/MMBtu	Emission limit corresponding to use of a VOC capture and control with thermal or catalytic incineration (98% control) or equivalent	Emission limit corresponding to use of a wet scrubber (95% control)	Emission limit corresponding to use of high efficiency (1D-3D) cyclones and thermal incinerator in series (98.5% control) or equivalent
Storage tank (fixed roof)			Emission limit corresponding to use of a VOC control system capable of 99.5% or better control efficiency		
Storage tank (floating roof)			Emission limit corresponding to use of a VOC control system capable of 98% or better control efficiency		
Flare (ethanol production)	0.05 lb/MMBtu	0.37 lb/MMBtu	0.063 lb/MMBtu	0.00285 lb/MMBtu	0.008 lb/MMBtu

Class/Category of Source	NO_x	CO	VOC	SO_x	PM10
Liquid fuel loading operations			Emission limit corresponding to use of a VOC control system capable of 98% or better control efficiency		
Liquid fuel transfer and dispensing operations			Emission limit corresponding to use of an ARB certified Phase I vapor recovery system		
Biomass-fired boiler	0.012 lb/MMBtu (*9 ppmvd @ 3% O_2*)	0.046 lb/MMBtu (*59 ppmvd @ 3% O_2*) Alternate Limit: 0.01 lb/MMBtu (*22 ppmvd @ 3% O_2*)	0.005 lb/MMBtu (*11 ppmvd @ 3% O_2*)	0.012 lb/MMBtu (*7 ppmvd @ 3% O_2*)	0.024 lb/MMBtu (*0.01 gr/scf @ 12% CO_2*)
Landfill gas-fired flare	0.025 lb/MMBtu	0.06 lb/MMBtu	Emission limit corresponding to 98% VOC destruction efficiency or 20 ppmv @ 3% O_2	Emission limit corresponding to use of a wet scrubber with 98% control efficiency	Emission limit corresponding to use of steam injection and/or knockout vessel
Manure digester and co-digester gas-fired flare	0.03 lb/MMBtu (*25 ppmvd @ 3% O_2*)	Operate per manufacturer specifications to minimize CO	0.03 lb/MMBtu	Emission limit corresponding to use of a H_2S removal system (dry or wet scrubber or equivalent)	Emission limit corresponding to use of smokeless combustion and LPG or natural gas-fired pilot
Compressed gas dispensing operations	No emissions – use of closed loop system with all vent and excess process gas directed to an on site treatment system, used in vehicles, or directed to another combustion or processing facility that can process the biogas and which has been issued a valid air permit				
Biomethane-fueled fuel cell[2]	0.5 lb/MWh Alternate Limit: 0.07 lb/MWh	6.0 lb/MWh Alternate Limit: 0.10 lb/MWh	1.0 lb/MWh Alternate Limit: 0.02 lb/MWh	N/A	N/A
Biomethane-fired microturbine	0.5 lb/MWh As of 1/1/2013: 0.07 lb/MWh	6.0 lb/MWh As of 1/1/2013: 0.10 lb/MWh	1.0 lb/MWh As of 1/1/2013: 0.02 lb/MWh	N/A	N/A

[2] Emission limits are the 2008 standards for waste gas required by the ARB's Distribution Generation (DG) Certification Regulation. Alternate limits represent the 2013 standards for waste gas required by the DG Certification Regulation.

Class/Category of Source	NO_x	CO	VOC	SO_x	PM10
Biomethane-fired reciprocating internal combustion engine	11 ppmvd @ 15% O_2 (or 0.15 g/bhp-hr) in conjunction with an effective and efficient biogas treatment system Alternate Limit for dairy digester gas-fired rich-burn engines: 9 ppmvd @ 15% O_2 (or 0.15 g/bhp-hr)	250 ppmvd @ 15% O_2	20 ppmvd @ 15% O_2	Emission limit corresponding to use of a fuel gas pretreatment system for sulfur removal along with maximum fuel sulfur content limit	0.1 g/bhp-hr
Biomethane-fired turbine, <3 MW	9 ppmvd @ 15% O_2	60 ppmvd @ 15% O_2	3.5 ppmvd @ 15% O_2[3]	Landfill gas: Emission limit corresponding to use of landfill gas with sulfur content of no more than 150 ppmv as H_2S Digester gas: Emission limit corresponding to use of digester gas with sulfur content of no more than 40 ppmv as H_2S	Emission limit corresponding to use of a fuel gas pretreatment system for particulate removal
Biomethane-fired turbine, ≥3 MW	5 ppmvd @ 15% O_2				
Biomass syngas-fueled reciprocating internal combustion engine	5 ppmvd @ 15% O_2	N/A	25 ppmvd @ 15% O_2	N/A	N/A

[3] Due to limited data set available for this Report on achievable VOC emission levels for landfill and digester gas-fired turbines, ARB staff recommends that regulatory agencies consult with the manufacturers on guaranteed emission levels, as well as, evaluate additional source tests to determine the appropriate VOC limit for a turbine.

Class/Category of Source	NO_x	CO	VOC	SO_x	PM10
Composting			Emission limit corresponding to use of a VOC control system (enclosure with biofilter or equivalent) capable of 80% or better control efficiency Ammonia: Emission limit corresponding to use of an NH3 control system capable of 80% or better control efficiency		Emission limit corresponding to use of a PM10 control system capable of 99% or better control efficiency
Diesel-fueled emergency engine generator	Cleanest available U.S. EPA Tier certification level for applicable horsepower range[4]	Cleanest available U.S. EPA Tier certification level for applicable horsepower range	Cleanest available U.S. EPA Tier certification level for applicable horsepower range	Emission limit corresponding to use of CARB, or very low sulfur, diesel fuel (15 ppm sulfur by weight)	Cleanest available U.S. EPA Tier certification level for applicable horsepower range

9. What are the available options to mitigate mobile source emissions associated with biorefineries?

On-road vehicles, off-road vehicles, and portable equipment used at biorefineries are a source of criteria pollutants, TACs, and GHGs. These mobile sources may be used for the following activities associated with biorefineries:

- construction and maintenance;
- delivery of raw product;
- processing of raw material and finished fuel product; and
- delivery of finished fuel product.

The following are available options to mitigate mobile source emissions associated with biorefineries:

- Repower, retrofit, new purchases, replace, or use of alternative fuels to achieve earlier, more aggressive, or more comprehensive (e.g., including exempt equipment) emission reductions that go beyond regulatory requirements for in-use diesel-fueled mobile sources; and

[4] Refer to U.S. EPA regulations and/or Appendix D Table D-29 of this Report for the applicable emission standard.

- Application of other available mitigation options contained in Table IX-1 to mitigate mobile source emissions that are associated with the construction and operation of biorefineries.

10. How will this Report be updated?

ARB staff will establish a website to post future BACT determinations, source test results, new technologies, newly approved regulations (including test methods), and a current list of existing biorefineries in California. As part of these updates, staff will assess the geographic distribution of biorefineries in the state, and where appropriate, integrate additional mitigation measures for the purpose of protecting against air quality impacts that arise from the concentration or co-location of multiple biorefineries. When these updates are posted to the website, ARB staff will send e-mail notifications to the LCFS listserve at ARB, and the Bioenergy listserve at CEC.

11. Are there general policies that should be considered in addition to those discussed in this Report that could further mitigate emissions from biorefineries?

This Report provides the most current stringent emission levels identified for process equipment used at biorefineries and available options to mitigate mobile source emissions associated with biorefineries. The following are currently recommended as additional broad strategies to mitigate emissions from biorefineries:

- Promote the use of pipeline injection of biogas, rather than on-site combustion of biogas as a strategy to reduce emissions of NO_x in areas that do not achieve the federal or State Ambient Air Quality Standards for ozone;
- Promote the use of and explore economic and regulatory incentives for the maximum recovery of energy (particularly waste heat recovery) and other marketable by-products associated with biorefineries;
- Promote the use of and explore economic and regulatory incentives for cost effective and energy efficient emerging air pollution control strategies;
- Promote the use of and explore economic and regulatory incentives for fuel cells, microturbines, and other ultra-clean technologies that can be fueled by biomethane; and
- Except for emergency purposes, minimize flaring of biogas or biofuel produced from biomass feedstocks.

12. How might project proponents use the information in this Report to inform stakeholders interested in the activities related to site selection, district permitting, and mitigation of air emissions associated with new or expanding biorefineries?

This Report can assist stakeholders in evaluating the relative air quality impacts of the various conversion technology options that are available for the biofuels addressed by this Report. Proponents of biorefinery projects may use this Report to inform environmental and public health groups and other interested stakeholders about the emissions levels of proposed stationary equipment at biorefineries. In addition, this Report provides project proponents with a range of options that could be used to mitigate mobile source emissions that are associated with the construction and operation of biorefineries. These options include obtaining mobile source emission reductions beyond what is required by in-use mobile source emission reduction regulations. Other options include minimizing the emissions from new or increased traffic from biorefineries by considering the use of routes that circumvent neighborhoods and sensitive receptors. This Report also provides options that could be considered by project proponents to reduce vehicle emissions that are associated with employees at a biorefinery.

The information in this report should be included in outreach activities that project proponents conduct to solicit stakeholder input on the site selection process and mitigation of both stationary and mobile source emissions. These outreach activities include holding public meetings during the project development phase; wide distribution of draft air permits and CEQA-related documents; and solicitation of input from fleet owners interested in potentially reducing equipment emissions beyond what is required by existing regulations.

I.

BIOFUEL PRODUCTION CONVERSION TECHNOLOGIES

This section contains a description of the biofuel production conversion technologies ARB staff determined are either currently available or industry has indicated will soon be available for commercial use in California. Appendix C contains a listing of all the biomass feedstocks that could theoretically be used to produce biofuels.

A. Ethanol

Ethanol is produced by the fermentation of sugar obtained from grains, sugarcane, and cellulose.

1. Ethanol from grains

The typical grain feedstocks for the production of ethanol include corn and wheat. Grains contain starch, a polymer of glucose, which must be broken apart before the sugar can be fermented. There are two methods for processing grain feedstock: dry mill and wet mill. Both are followed by fermentation to produce ethanol.

a. Dry mill processing/Fermentation

Grain feedstock is milled into a flour or fine meal to expose the starch. The material is then mixed with water to produce a mash. The mash is processed in a high temperature cooker with enzymes to convert the starch to sugar and reduce bacterial contamination. After the starch has been hydrolyzed to its component sugars, it is fermented using yeast under anaerobic conditions. After fermentation, the resulting ethanol is concentrated using conventional distillation methods. Distillation is followed by purification of the ethanol. The by-products of fermentation are known as distillers' grain. Distillers' grain may be partially dried and mixed with solids to produce wet distillers' grain with solids or further dried to produce dry distillers' grain with solids. Both may be used as animal feed.

b. Wet mill processing/Fermentation

Grain feedstock is steeped in water and a dilute sulfurous acid solution for one to two days. After the grain has finished steeping, the slurry is passed through a series of grinders, centrifuges, screens, and separators, which separate the corn into starch, protein, fiber, and germ. The starch and remaining water are processed into ethanol by a fermentation process similar to the dry mill production process described above. The resulting distillers' grain may be used as discussed above. Fermentation is followed by distillation and purification of the ethanol.

2. Sugarcane Ethanol

Potential sugar feedstocks for the production of ethanol include sugar cane; sweet sorghum, sugar beets, molasses, and surplus sugar from sugar refining plants.

a. Fermentation

Sugar syrup from pressed sugar crops is fermented by yeast under anaerobic conditions with minimal pre-processing. Fermentation is followed by distillation and purification of the ethanol as described above for corn ethanol production.
The dry, fibrous residue remaining after the extraction of juice from the pressed sugar crops is known as bagasse. Bagasse may be used as animal feed, a potential feedstock for cellulosic ethanol, or burned for electricity.

3. Cellulosic Ethanol

Potential cellulosic feedstocks for the production of ethanol include dedicated crops, crop and forest residues, bagasse from sugar crops, municipal solid waste, and furniture manufacturing by-products. Cellulosic feedstock is made up of cellulose and hemicellulose. Both are polymers of various sugars that can be hydrolyzed and fermented to form ethanol. There are two methods for producing ethanol from cellulosic feedstock: hydrolysis followed by fermentation and gasification followed by Fischer-Tropsch (FT) synthesis or fermentation.

a. Hydrolysis/Fermentation

Cellulosic feedstock is cleaned and chipped to the proper size. A chemical pretreatment hydrolyzes the hemicellulose to its component sugars. Following pretreatment, cellulose is hydrolyzed to glucose. There are two methods of hydrolysis used to break down cellulose to glucose. The enzyme hydrolysis process uses enzymes, while the acid hydrolysis process uses acids as catalysts. The resulting glucose is fermented using microorganisms under anaerobic conditions. Fermentation is followed by distillation and purification of the ethanol.

b. Gasification/Alcohol Synthesis

Cellulosic feedstock is dried and chipped to the proper size. It is then fed to a gasifier where it is thermally decomposed in a controlled oxygen atmosphere at high temperatures. Gasification of the cellulosic feedstock produces synthesis gases (syngas) that include hydrogen, methane (CH_4), nitrogen, and light hydrocarbons, which can be used to produce ethanol. There are two methods for producing ethanol from syngas: modified FT synthesis and fermentation.

(1) Modified Fischer-Tropsch Synthesis

Syngas is compressed and treated to reduce acid gas concentrations. Following further compression, it is heated to alcohol synthesis reaction conditions. The syngas is converted to mixed alcohols in a fixed bed reactor in the presence of a catalyst. The mixed alcohol stream is dehydrated and introduced to a separation column to separate methanol and ethanol from the other alcohols.

(2) Fermentation

Syngas is conditioned and compressed for fermentation. The syngas is fermented to ethanol using genetically engineered microorganisms under anaerobic conditions. Fermentation is followed by distillation and purification of the ethanol.

B. Biodiesel

Potential feedstocks for the production of biodiesel include plant oils, such as soybean and peanut; and animal fats, such as restaurant grease and tallow from rendering plants.

1. Transesterification

Raw oils and fats are filtered and pretreated to remove water and contaminants. Following pretreatment, the oils and fats are mixed with an alcohol in the presence of a catalyst in a closed-reactor system at low temperature and pressure. The oils and fats are converted to fatty acid methyl esters and glycerin, which are separated and purified. Excess alcohol and impurities are removed from the crude biodiesel. The glycerin by-product can be purified and used in the pharmaceutical or cosmetic industries.

C. Renewable Diesel

Potential feedstocks for the production of renewable diesel include waste fats; plant oils; and biomass feedstocks, such as crop and food processing residues, green landscaping or food waste, paper, and wood waste. There are four methods for producing renewable diesel: hydrogenation, coproduction, flash pyrolysis followed by hydrotreatment, and gasification followed by FT synthesis. Fuel produced by these processes is referred to as renewable diesel to differentiate it from biodiesel produced by transesterification.

1. Hydrogenation

Plant oils and animal fats are refined to produce hydrogenation-derived renewable diesel. The oil or fat is upgraded into diesel, propane, and other light hydrocarbons through hydrotreatment with hydrogen.

2. Coproduction

Waste fat is preheated then mixed with a distilled crude oil stream and processed in a hydrotreater. The coproduction process also produces propane and petroleum products.

3. Flash Pyrolysis/Hydrotreatment

The biomass feedstock is dried and chipped to the proper size for rapid heat transfer. The pyrolysis reaction occurs in a fluidized bed reactor using an inert material such as sand to transfer heat to the incoming biomass particles. The biomass is flash vaporized and becomes a mixture of gas, vapor, aerosols, and solid char. The gases are separated using a cyclone and then enter a quench tower where they are cooled and condensed into liquid “bio-oil”. The bio-oil is refined through hydrotreatment to produce renewable diesel. Pyrolysis also produces gaseous fuels, solid carbon, and/or char. Excess heat captured from the pyrolyzer can be used to produce hot water or steam for other processes.

4. Gasification/Fischer Tropsch Synthesis

The biomass feedstock is dried and chipped to the proper size. It is then thermochemically converted to syngas through gasification. Following clean-up, the syngas is sent to a low temperature FT reactor with a metal catalyst. The liquids produced by the FT reactor can be upgraded to diesel using a combination of hydrotreatment, hydrocracking, and hydroisomerization methods. The by-product gases produced from the FT reactor can be diverted and recycled back through the reactor to generate additional hydrocarbon products, or they can be used to generate power or steam.

D. Biogas

Potential feedstocks for the production of biogas include animal manure, food and yard waste, dedicated energy crops, food processing waste, organic material in landfills, and biosolids.

1. Anaerobic Digestion

Biomass feedstock is broken down by bacteria to fatty acids, alcohol, carbon dioxide (CO_2), hydrogen, ammonia and sulfides. Acid-forming bacteria further metabolize the products of hydrolysis into acetic acid, hydrogen and CO_2. Finally, methane forming (methanogenic) bacteria convert these products into a biogas containing CH_4, CO_2, sulfur compounds, PM, and water. Anaerobic digestion also produces residues that can be used as soil amendments or animal bedding.

a. Landfill Gas

Organic waste in municipal solid waste landfills decomposes to produce landfill gas. Landfill gas can be used as a transportation fuel in the form of compressed natural gas (CNG) or liquefied natural gas (LNG). Production of CNG from landfill gas requires removal of water, pretreatment to remove trace organics and CO_2, and compression. Production of LNG from landfill gas requires a cryogenic process to liquefy it.

b. Digester Gas

Digester gas contains CH_4, CO_2, sulfur compounds, PM, and water. Removing almost all of the CO_2, sulfur compounds, PM, and water from the biogas generated by a digester produces biomethane. After pretreatment and compression, biomethane can be used as a transportation fuel.

E. Hydrogen

Potential biomass feedstocks for the production of hydrogen include crop and food processing residues, green waste, paper, wood waste; and biogas. There are two methods for producing hydrogen: gasification and reformation.

1. Gasification

Biomass feedstock is dried and chipped to the proper size. It is then thermochemically converted to syngas through gasification. The syngas is then processed to remove impurities.

2. Reformation

Methane-rich biogas reacts with steam under pressure in the presence of a catalyst to produce hydrogen, CO, and a small amount of CO_2. CO and steam are reacted using a catalyst to produce CO_2 and additional hydrogen. The syngas is then processed to remove impurities.

F. Biogasoline

Biogasoline is gasoline produced from biomass feedstock. Like traditional gasoline, it can be used in internal-combustion engines (IC engine).

1. Acid Fermentation

Biomass feedstock is treated with lime to enhance its digestibility. The lime-treated biomass is fermented to produce a mixture of carboxylic acids. Calcium carbonate is added to neutralize the acids to form their corresponding carboxylate salts. These salts are then dewatered, concentrated, dried and thermally converted to ketones, which are hydrogenated to alcohols. The resulting carboxylic acids, ketones, primary alcohols, and secondary alcohols can be distilled to produce gasoline, diesel and jet fuel.

II.

BIOREFINERIES IN CALIFORNIA

A. List of Existing Facilities

ARB staff obtained current information from NACAA, and the Working group to identify biofuel production facilities operating in California. ARB staff then requested permit information from the districts for each facility identified.

Table II-1 provides a list of biorefineries in California. However, it should not necessarily be construed as a comprehensive list of biorefineries in California. There may be additional biorefineries in the permitting or planning process; or that fall below the permitting threshold that staff are not aware of.

Table II-1. Biodiesel Facilities in California

Facility Name	Responsible Air District	Conversion Process	Production Rate (MMgal/yr)	Status
American Biodiesel, Inc. dba Community Fuels	San Joaquin Valley APCD	Transesterification	11.75	Operational
Blue Sky Bio-Fuel, Inc.	Bay Area AQMD	Transesterification	10	Operational
Crimson Renewable Energy, LP	San Joaquin Valley APCD	Transesterification	30	Construction Complete
Energy Alternative Solutions, Inc.	Monterey Bay APCD	Transesterification	1	Operational
Geogreen Biofuel	South Coast AQMD	Transesterification	2.19	Operational
Golden Gate Petroleum Company	Bay Area AQMD	Transesterification	10	In Permitting
Imperial Western Products, Inc.	South Coast AQMD	Transesterification	8	Operational
New Leaf Biofuels, LLC	San Diego APCD	Transesterification	1.7	Operational
Noil Energy Group, Inc.	South Coast AQMD	Transesterification	5	Under Construction
Renewable Energy Products, LLC	South Coast AQMD	Transesterification	10	Under Construction
Simple Fuels Biodiesel	Northern Sierra AQMD	Transesterification	5	In Permitting
Whole Energy Fuels Corporation	Bay Area AQMD	Transesterification	3	Under Construction
Wright Biofuels	South Coast AQMD	Transesterification	5.5	Operational
Yokayo Biofuels, Inc.	Mendocino County AQMD	Transesterification	0.35	Operational

Table II-2. Renewable Biodiesel Facilities in California

Facility Name	Responsible Air District	Conversion Process	Production Rate (MMgal/yr)	Status
Kern Oil & Refining Co.	San Joaquin Valley APCD	Not Available	5.3	Operational

Table II-3. Corn Ethanol Facilities in California

Facility Name	Responsible Air District	Conversion Process	Production Rate (MMgal/yr)	Status
Altrabiofuels, Phoenix Bio Industries	San Joaquin Valley APCD	Dry Mill / Fermentation	31.5	Operational
Calgren Renewable Fuels LLC	San Joaquin Valley APCD	Dry Mill / Fermentation	60	Operational
Cilion Ethanol (Keyes)	San Joaquin Valley APCD	Dry Mill / Fermentation	55	Under Construction
Great Valley Ethanol (Hanford)	San Joaquin Valley APCD	Dry Mill / Fermentation	60	In Permitting
Pacific Ethanol, Brawley	Imperial County APCD	Dry Mill / Fermentation	60	Under Construction
Pacific Ethanol, Madera	San Joaquin Valley APCD	Dry Mill / Fermentation	40	Operational
Pacific Ethanol, Stockton	San Joaquin Valley APCD	Dry Mill / Fermentation	60	Operational
Parallel Products, Rancho Cucamonga	South Coast AQMD	Fermentation/ Distillation	5	Operational

Table II-4. Sugarcane Ethanol Facilities in California

Facility Name	Responsible Air District	Conversion Process	Production Rate (MMgal/yr)	Status
Cal. Ethanol & Power LLC	Imperial County AQMD	Fermentation	Not Available	Planned

Table II-5. Cellulosic Ethanol Facilities in California

Facility Name	Responsible Air District	Conversion Process	Production Rate (MMgal/yr)	Status
BlueFire, Lancaster	AVAQMD	Hydrolysis / Fermentation	3.1	Permitted

Table II-6. CNG Facilities in California

Facility Name	Responsible Air District	Conversion Process	Production Rate (ft^3/day)	Status
Calgren Renewable Fuels LLC	SJVAPCD	Anaerobic Digestion	290,000	Planned
Folsom Prison (Clean World Partners)	SMAQMD	Anaerobic Digestion	400,000	Planned

Table II-6. CNG Facilities in California (cont.)

Facility Name	Responsible Air District	Conversion Process	Production Rate (ft^3/day)	Status
Hilarides Dairy	SJVAPCD	Anaerobic Digestion	Not Available	Operational
Northstate Rendering	BCAQMD	Anaerobic Digestion	150,000	Planned
Puente Hills Landfill	SCAQMD	Landfill Digestion	360,000	Currently not Operating
Sacramento Regional WTP	SMAQMD	Anaerobic Digestion	Not Available	Planned
Sonoma Central Landfill	BAAQMD	Landfill Digestion	Not Available	Operational

Table II-7. LNG Facilities in California

Facility Name	Responsible Air District	Conversion Process	Production Rate (MMgal/yr)	Status
Simi Valley Landfill	VCAPCD	Landfill Digestion	6.0	Planned
Altamont Landfill	BAAQMD	Landfill Digestion	4.7	Operational
Bowerman Landfill	SCAQMD	Landfill Digestion	6.8	Operational
Kiefer Landfill	SMAQMD	Landfill Digestion	4.5	Operational

Table II-8. Hydrogen Fuel Facilities in California

Facility Name	Responsible Air District	Conversion Process	Production Rate (ft^3/day)	Status
Orange County Sanitation District	SCAQMD	Fuel Cell	56,000	Operating

III.

REGULATION OF STATIONARY SOURCE EMISSIONS

Large industrial sources, such as refineries, factories, and power plants, as well as smaller retail gasoline service stations, dry cleaners, and bakeries, are known as "stationary sources." This section provides an overview of the air quality regulatory requirements for new or expanding biorefineries in California.

A. Regulatory Structure

The regulation of stationary sources is conducted at three levels of government in California: federal, State, and local. The federal Clean Air Act (FCAA) requires states to directly regulate both stationary and mobile sources through a SIP to provide for implementation, maintenance, and enforcement of health-based pollutant thresholds called national ambient air quality standards. The SIP outlines all of the national, statewide, and regional strategies that will be used to meet air quality standards by a given date. At the federal level, U.S. EPA is responsible for implementation of the FCAA. Some portions of the FCAA are implemented directly by U.S. EPA. Other portions are implemented by state and local agencies.

Responsibility for attaining and maintaining ambient air quality standards in California is divided among ARB and the 35 districts. ARB and the districts follow the laws enacted by the California Legislature in the California Health and Safety Code and regulations promulgated by the U.S. EPA to do what is necessary to meet the requirements of the State and federal Clean Air Acts. The air pollution laws in the Health and Safety Code are very general, so ARB and the districts must adopt regulations to implement the laws. Both State and federal law address pollutants like ozone and fine particulate matter, as criteria pollutants, and toxic pollutants like benzene and lead, as TACs.

B. Stationary Source Permitting

This section summarizes the primary legal requirements for permitting stationary sources of air pollution in California. Each district has adopted a set of rules as part of the SIP to meet State and federal ambient air quality standards. District rules define the procedures and criteria that districts are to use in permitting stationary sources. Although specific rules vary among the districts in scope and level of stringency depending on the region's air quality status, the general procedure for permitting new and expanding sources is the same throughout the State. Most pollutant-emitting sources must obtain an authority to construct (ATC) before beginning construction, and a permit to operate after the completed facility demonstrates compliance with district rules and the facility's permit conditions. Where applicable, district permit programs incorporate federal stationary source program requirements.

District requirements for stationary sources generally fit into two categories. The first category of rules applied to stationary sources is permitting rules for the construction and operation of new and expanding stationary sources. These rules are referred to as the New Source Review (NSR) program. A second category of requirements includes rules which every source, or every source in a certain category of sources, must meet. These are often referred to as prohibitory rules. The rules apply whether a source is new or existing.

1. New Source Review/Prevention of Significant Deterioration

The NSR program allows industrial growth to continue in polluted areas without undermining progress toward meeting clean air standards. NSR rules apply in areas that do not comply with ambient air quality standards (i.e., nonattainment areas). Because most districts are nonattainment for at least one criteria pollutant, NSR is a key component of stationary source permitting programs. NSR rules regulate new or expanding stationary sources that emit or have the potential to emit any criteria pollutant (or precursor) for which there is a State or federal ambient air quality standard. NSR programs provide mechanisms to (1) reduce emission increases up-front through the use of clean technology, (2) provide for a no net increase in emissions, and (3) result in a net reduction in emissions. This is accomplished through two major requirements in each district NSR rule: BACT and offsets.

2. Best Available Control Technology

BACT is required for new and expanding equipment or processes at stationary sources that result in emission increases above designated thresholds. BACT requires use of the cleanest, state-of-the-art technology to achieve the greatest feasible emission reductions. Significant reductions in criteria pollutants have been achieved using this technology-based approach to air pollution control. For example, BACT emission levels for NO_x in California are 98 percent less than in 1982 for power plant gas turbines and 91 percent less than in 1983 for gas-fired industrial boilers.

3. Emission Offsets

In addition to BACT requirements, owners of new or expanding sources may be required to mitigate, or offset, the increased emissions that result after installation of BACT. Offsetting is the use of emission reductions from existing sources to offset emission increases from new or expanding sources. The amount of offsets required depends on the distance between the source of offsets and the new or expanding source. Offsets are generally required at a greater than 1-to-1 ratio. If a source obtains emission offsets outside the local area (i.e., interbasin), or if one type of pollutant is offset against another type (i.e., interpollutant), the source must use air quality modeling to show that these offsets will result in a net benefit. Some districts have pre-established ratios for interpollutant offsets in their rules.

If a stationary source reduces emissions below actual emission levels allowed by the district, then in some cases the source may "bank" the reduction in emissions to offset emissions from future projects. Emissions banked in this manner are called emission reduction credits (ERC) and can be used as offsets by the source or sold to other sources. ERCs must meet specific criteria before they can be issued. Criteria include that actual emission levels reduced be adequately documented via records, emissions are in addition to that which are required by law, and there be mechanisms in place to ensure those reductions continue into the future.

4. Prohibitory Rules

Each district has rules aimed at limiting emissions from new and existing stationary sources, known as prohibitory rules. Prohibitory rules may be generic, such as limiting the maximum level of a particular pollutant (such as NO_x) at any facility; or they may address specific equipment, such as a turbine, a boiler, or a reciprocating IC engine. Sources are also subject to a general nuisance rule which provides authority to the district to control the discharge of any air contaminants that will cause injury, detriment, nuisance, endangerment, discomfort, annoyance, or which have a natural tendency to cause damage to business or property. Except where a source is exempt from permitting, the proponent of a new or expanding source will typically have to demonstrate compliance with both NSR and prohibitory rule requirements in any permit application submitted to the district.

5. Toxic Air Contaminant Requirements/Health Risk Assessment

Most districts evaluate TAC emissions at the same time that criteria pollutants are evaluated during the air permitting process. Sources emitting TACs must comply with district requirements regarding the risk assessment and risk management (mitigation) of these emissions. Some districts have established acceptable levels of health risk. Screening comprehensive health risk assessments (HRA) may be required as part of the permitting process, or as part of the State AB 2588 Hot Spots Program. In the case of significant health risks, districts may require mitigation measures to reduce risk. In addition, a new or expanding source, as well as existing sources, may be subject to either a federal NESHAP, a State-mandated airborne toxic control measure (ATCM) promulgated by ARB, or both.

As mentioned above, the impacts of TACs that are emitted from a stationary source project are addressed by an HRA. An HRA is an evaluation of the potential for adverse health effects that can result from public exposure to emissions of toxic substances. The information provided in an HRA can be used to decide if or how a project should proceed, including a requirement for additional mitigation measures. Some districts have regulations, or established policies, on using the results of HRAs to make risk management decisions.

An HRA addresses three categories of health impacts from various pathways of exposure: acute health effects, chronic non-cancer health effects, and cancer risks. Acute health effects generally result from short-term exposure to high concentrations of pollutants. Chronic non-cancer health effects and increased cancer risks may result from long-term exposure to relatively low concentrations of pollutants.

Air dispersion models are used to predict the ambient air concentrations of the toxic substances emitted by the source. The output from modeling is combined with pollutant-specific factors called unit risk factors (for cancer effects) or reference exposure levels (for acute and chronic non-cancer health effects). This information provides an estimate of the potential cancer risk (in chances per million) and potential non-cancer impacts expressed as a hazard index. Depending on the results, the district may approve the project as is, require additional pollution controls that represent the BACT for reducing TACs, or may reject the project altogether.

6. Ambient Air Quality Modeling

In California, most district permitting rules require evaluation of the air quality impacts of a project to be based on proposed emissions of the project. Rarely will district permitting requirements be based on the results of air quality modeling. Usually, air quality modeling is only required when emission offsets are not provided. As a result, air quality modeling is primarily used to demonstrate that the project does not create a new violation of a State or federal ambient air quality standard, or exacerbate an existing one. If there are projected new violations of standards, including Prevention of Significant Deterioration (PSD) requirements, the project may not be approved, unless acceptable mitigation measures are provided.

C. Federal Program

In addition to the district rules, there are also federal rules which govern the permitting of new or expanding stationary sources—federal NSR and PSD. Similar to "California NSR," the purpose of federal NSR is to ensure that air quality does not deteriorate in areas with bad air quality ("nonattainment areas"). PSD ensures that areas with good air quality will continue to maintain good air quality ("attainment areas"). Many district rules incorporate these federal regulations by reference.

D. California Environmental Quality Act Requirements

Before the district can issue or deny a permit for a project which may have a significant effect on the environment, the project must comply with CEQA. The purpose of CEQA is to ensure that the environmental impacts of a project and its alternatives are disclosed to governmental decision-makers and the public, and that any significant effects are mitigated to the maximum extent feasible. By law, no regulatory agency is allowed to issue any permits until the project has been approved by the lead agency. The lead agency is generally the agency with the broadest discretionary authority in approving the project. This is typically the local land use agency, such as a county planning department. However, in some cases, the local air district could be the lead agency.

If a project is not exempt from CEQA review, it is analyzed to determine if there is the possibility of a significant effect on the environment. If a significant effect is possible, the lead agency prepares an initial study to evaluate the potential for an effect. If there are no potential significant effects, a negative declaration is issued by the lead agency. If a potential significant effect exists which the project proponent can and will commit to mitigate, a mitigated negative declaration can be issued. Otherwise, the lead agency will issue a notice of preparation of an EIR. At this point, responsible agencies may comment on the EIR. These comments are then used by the lead agency to produce a draft environmental impact report (DEIR). The purpose of a DEIR is to assess any significant effect on the environment by the project and to evaluate potential mitigation measures. This report is available for review by responsible agencies and the public during the public review period. Comments on the DEIR by any of these parties may be submitted prior to the end of the public review period on such topics as completeness and accuracy of the draft EIR. The lead agency then reviews these comments and prepares a final EIR with responses to comments on the draft EIR. The final EIR is used by the lead agency in approving the project and by responsible agencies in issuing permits.

Unlike district rules, CEQA analyses must consider significant effects of facility construction, indirect emissions from increased mobile source activity, and the cumulative impacts of other projects within the area. For example, construction impacts might include fugitive dust emissions raised by mobile construction equipment. Indirect emissions may include emissions from trips to and from work by employees as well as increases in emissions from commercial vehicles using the facility. Cumulative impacts include consideration of the individual effects from the project, other current projects, and reasonably foreseeable future projects. Air quality impacts can be estimated using air quality modeling. The significance of new emissions can be compared to growth projections of emission forecasts in the SIP. Using the results of these analyses, the lead agency will evaluate the need for mitigation measures before approving the project.

IV.

STATIONARY SOURCES OF EMISSIONS FOR EACH BIOFUEL CONVERSION TECHNOLOGY

This chapter summarizes the stationary sources of emissions and their associated pollutants for the biofuel production conversion technologies addressed by this Report. The equipment and emission points identified are based on facility designs from permits acquired by ARB staff and therefore should not be construed to reflect a one-size-fits-all profile. This chapter is intended to provide an overview of the typical equipment at biorefineries that is expected to be subject to air regulatory program requirements.

A. Process Equipment Used at Biorefineries

Table IV-1 is a compilation of the stationary source process equipment used at biofuel production facilities that is expected to trigger air regulatory program review. The table identifies which equipment is associated with each biofuel.

Table IV-1. Process Equipment Requiring an Air Permit by Biofuel

Process Equipment/ Emission Point	Biofuel						
	Grain Ethanol	Sugarcane Ethanol	Cellulosic Ethanol	Biodiesel	Renewable Diesel	Biogas	Hydrogen
Grain/feedstock receiving, conveying, and grinding operations	X	X	X		X		
Fermentation process- yeast, liquefaction, beerwell, and process condensate tanks	X	X	X				
Distillation and wet cake process	X	X	X				
Natural-gas fired boiler	X	X	X	X			
Pumps and compressor seals	X	X	X	X			
Valves, flanges, and other connectors	X	X	X	X		X	
Wet Cooling tower	X	X	X				
Storage tanks (fixed roof)				X	X		
Storage tanks (floating roof)	X	X	X				
Biomass-fired boiler	X	X	X				
Dryer	X						
Flare	X	X	X			X	
Compressed gas dispensing operation						X	
Biomethane fuel cell						X	X
Compost piles						X	X
Biomethane-fired microturbine						X	
Biomethane-fired						X	

Process Equipment/ Emission Point	Biofuel						
	Grain Ethanol	Sugarcane Ethanol	Cellulosic Ethanol	Biodiesel	Renewable Diesel	Biogas	Hydrogen
reciprocating IC engine							
Biomethane-fired turbine						X	
Pyrolyzer	X	X	X		X	X	
Syngas-fired reciprocating IC engine[5]	-	-	-	-	-	-	-
Diesel-fueled emergency engine generator	X	X	X	X	X	X	X

B. Pollutants Associated with Process Equipment Used at Biorefineries

Table IV-2 identifies the pollutants associated with the stationary source process equipment that is expected to trigger air regulatory program review.

Table IV-2. Air Pollutants Associated with Processes Used at Biorefineries

Process Equipment/ Emission Point	Pollutant				
	NO_x	CO	VOC	SO_x	PM10
Grain/feedstock receiving, conveying, and grinding operations					X
Fermentation process- yeast, liquefaction, beerwell, and process condensate tanks			X		
Distillation and wet cake process			X		
Natural-gas fired boiler	X	X	X	X	X
Pumps and compressor seals			X		
Valves, flanges, and other connectors			X		
Wet cooling tower					X
Storage tanks (fixed roof)			X		
Storage tanks (floating roof)			X		
Biomass-fired boiler	X	X	X	X	X
Dryer	X	X	X	X	X
Flare	X	X	X	X	X
Compressed gas dispensing operation	-	-	-	-	-
Biomethane fuel cell	X	X	X	X	X
Compost piles			X		X
Biomethane-fired microturbine	X	X	X	X	X
Biomethane-fired reciprocating IC engine	X	X	X	X	X
Biomethane-fired turbine	X	X	X	X	X
Pyrolyzer	X	X	X	X	X
Syngas-fired reciprocating IC engine	X	X	X	X	X
Diesel-fueled emergency engine generator	X	X	X	X	X

[5] ARB staff located one biomass-derived syngas-fired engine. The engine drives a generator to produce electricity and is not used to produce transportation fuels, so it is not included in the table.

V.

EMISSIONS PERFORMANCE OF STATIONARY SOURCE EQUIPMENT USED AT BIOREFINERIES

This chapter discusses ARB staff's supporting documentation for the most current stringent permitted emission levels identified in Table ES-1 of the Executive Summary for criteria pollutants emitted from stationary source equipment at biorefineries.

In identifying the most current stringent permitted emission levels for equipment used at biorefineries, ARB staff reviewed control technologies and corresponding emission levels contained in the following sources:

- adopted and proposed district rules;
- control techniques required as BACT;
- permitted emission levels achieved in practice, as verified by test results; and
- more stringent control techniques which are technologically and economically feasible, but are not yet achieved in practice.

The above sources were obtained from ARB and other regulatory agency BACT guidance documents; BACT determinations listed in the Bay Area Air Quality Management District (BAAQMD), California Air Pollution Control Officers Association (CAPCOA), South Coast Air Quality Management District (SCAQMD), and San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT clearinghouses; U.S. EPA RACT/BACT/LAER[6] Clearinghouse; California air district rules; and air permits and corresponding source tests. The references that ARB staff used as the basis for each emission limit are referenced in this chapter by the table and number they have been assigned in Appendix D.

This Report was developed to assist air quality agencies, local land use planners, environmental and public health groups, project proponents, and other stakeholders conducting air quality evaluations for new or expanding biorefineries. Stakeholders may also find this Report useful during site selection, air quality permitting, and identification of potential CEQA mitigation measures. This document can also assist stakeholders in evaluating the relative air quality impacts of the various conversion technology options that are available for the biofuels addressed by this Report.

This Report should be used in combination with other air quality information, such as air quality attainment status, progress in achieving commitments contained in SIPs, site-specific modeling, availability of potential emissions mitigation measures, proximity to sensitive land uses, local health risk management policies, and availability of potential mobile source mitigation measures.

This Report can be used as a starting point in conducting air quality evaluations, but is

[6] RACT means reasonably available control technology; LAER means lowest achievable emission rate.

not intended to substitute for the case-by-case permitting decisions conducted by local air quality, environmental, or planning agencies.

This Report is not intended to establish new BACT, identify BARCT emissions levels, or verify emission levels claimed to be achievable by vendors of conversion technologies. BACT is determined on a case-by-case basis to account for advancements in technology and processes. In addition, this Report is not intended to pre-empt, replace, or devalue the decision-making processes that are associated with the outcomes of transportation planning analyses, site specific air quality modeling, risk assessments, SIP modeling, or future rules and regulations adopted for the purpose of controlling emissions of criteria pollutants, TACs, or GHGs.

A. Grain Receiving, Conveying, and Grinding Operations

1. Control of PM10 Emissions

PM10 is emitted when dry materials, such as corn, are handled and processed. The control devices available for mitigating PM10 emissions are the same as those used in other industries that handle and process dry product, such as cement manufacturing, sand and gravel processing, and food manufacturing operations.

The most stringent PM10 limit for grain receiving, conveying, and grinding operations is an emission level corresponding to the use of a baghouse with 99 percent control efficiency. This control method is required in the permit for Reference 1 in Table D-1. The requirement is consistent with PM10 BACT requirements for similar bulk material handing operations at comparable facilities, as shown in SCAQMD BACT guidelines (see References 3, 4, 5, and 6 in Table D-1). Therefore, ARB staff has identified the most stringent PM10 limit as the emission level corresponding to the use of a control system (baghouse, or equivalent technology) capable of 99 percent or better control efficiency.

B. Methanol/Sodium Methoxide Receiving and Storage

1. Control of VOC Emissions

The most stringent VOC limit for tanks involved in the receiving and storage of methanol or sodium methoxide is an emission level corresponding to the use of a VOC control system with 99.5 percent control efficiency. This is required in the permit for Reference 1 in Table D-2. The control efficiency can be met with distillation column and two-stage vapor condenser. Additional permits for methanol/sodium methoxide receiving and storage operations for biorefineries located in California require use of a VOC control system with 95 percent control efficiency (References 2, 3, and 4 in Table D-2). Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to the use of a VOC control system capable of 99.5 percent or better control efficiency.

C. Fermentation Process—Yeast, Liquefaction, Beerwell, and Process Condensate Tanks

2. Control of VOC Emissions

The most stringent VOC limit for tanks involved in the fermentation process is an emission level corresponding to the use of a VOC control system with 99.5 percent control efficiency. This is determined to be achieved-in-practice BACT for VOCs in SJVAPCD Guideline 4.12.4 (see Reference 3 in Table D-3). The control efficiency can be met with a fermentation wet scrubber vented to a CO_2 recovery plant with a condenser and high-pressure scrubber or equivalent technology. The VOC control efficiency was demonstrated in source tests for References 1 and 2 in Table D-3. Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to the use of a VOC control system (fermentation wet scrubber, high pressure scrubber, or equivalent technology) capable of 99.5 percent or better control efficiency.

D. Distillation and Wet Cake Processes

1. Control of VOC Emissions

The most stringent VOC limit for distillation and wet cake processes is an emission level corresponding to the use of a VOC control system with 95 percent control efficiency. This is required as achieved-in-practice BACT for VOCs in SJVAPCD Guideline 4.12.5 (see Reference 6 in Table D-4). The control efficiency can be met with a wet scrubber or equivalent technology. The VOC control efficiency is required in the permit for Reference 4 in Table D-4 and the ATC for Reference 2 in Table D-4. The limit was demonstrated in source tests for References 1, 3, and 5 in Table D-4. Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to the use of a VOC control system (wet scrubber or equivalent technology) capable of 95 percent or better control efficiency.

E. Natural Gas-fired Boiler

1. Control of NO_x Emissions

Natural gas-fired boilers used in the production of biofuels are no different from similar-sized boilers used in other commercial and industrial processes. Biorefinery permits received by ARB staff included those for boilers as small as 4.9 MMBtu/hr and as large as 75.6 MMBtu/hr. The recommendations for boilers are broken down into several source categories based on boiler heat input rating. This is consistent with district rules and BACT guidelines, as the availability and cost of emission controls are dependent on boiler capacity.

Boiler Heat Rating 2 to <5 MMBtu/hr
The most stringent NO_x limits of 9 ppmvd (at 3 percent O_2) for an operational non-

atmospheric natural gas-fired boiler and 12 ppmvd (at 3 percent O_2) for an operational atmospheric natural gas-fired boiler are required in SCAQMD Rule 1146.1 and SJVAPCD Rule 4307 (see References 1 and 2 in Table D-5) for boilers rated at 2.0 to less than 5.0 MMBtu/hr. The limits are based on emission levels achieved in practice by units located in these districts. Therefore, ARB staff has identified the most stringent NO_x limits as 9 ppmvd (at 3 percent O_2) for non-atmospheric boilers and 12 ppmvd (at 3 percent O_2) for atmospheric boilers rated at 2 to less than 5 MMBtu/hr.

<u>Boiler Heat Rating 5 to <20 MMBtu/hr</u>
The most stringent NO_x limit for an operational natural gas-fired boiler rated at 5 to less than 20 MMBtu/hr is 6 ppmvd at 3 percent O_2 (or 0.007 lb/MMBtu) and is required in SJVAPCD Rule 4320 (see Reference 18 in Table D-5). This limit is on the Enhanced Schedule and is more stringent than the Standard Schedule limit of 9 ppmvd at 3 percent O_2. According to the District's Staff Report for this rulemaking[7], the Enhanced Schedules were developed for boilers that could reach intermediate levels in the near future and then later achieve lower limits with more advanced technology. This allows operators to minimize their emissions by maximizing existing equipment and controls and postpone larger capital investments for selective catalytic reduction (SCR) or more advanced burners for the future. Therefore, the reason for the lower limits and extended compliance dates is not due to emission control technology constraints. New units must meet the applicable limits at the time of installation.

The next most stringent NO_x limit for an operational natural gas-fired boiler rated at 5 to less than 20 MMBtu/hr is 9 ppmvd (at 3 percent O_2) and is required in SJVAPCD Rule 4306 (see Reference 4 in Table D-5) as an enhanced option. As discussed in Rule 4320 above, the enhanced option provides an extended compliance date in exchange for a lower NO_x limit and is not due to emission control technology constraints.

Therefore, ARB staff has identified the most stringent NO_x limit as 6 ppmvd (at 3 percent O_2) for boilers rated at 5 to less than 20 MMBtu/hr.

<u>Boiler Heat Rating ≥20 MMBtu/hr</u>
The most stringent NO_x limit for an operational natural gas-fired boiler rated at 20 MMBtu/hr and greater is 5 ppmvd at 3 percent O_2 (or 0.0062 lb/MMBtu) and is required in SJVAPCD Rule 4320 (see Reference 18 in Table D-5). This limit is on the Enhanced Schedule and is more stringent than the Standard Schedule limit of 7 ppmvd at 3 percent O_2 (or 0.008 lb/MMBtu). As discussed above, the extended compliance dates allowed under the Enhanced Schedule provide additional time for operators to install advanced emission controls that require greater capital investment on existing units. New units are required to meet the applicable limits at the time of installation.

Boiler rules in the SCAQMD and BAAQMD further support the 5 ppmvd NO_x limit for

[7] SJVAPCD "Final Draft Staff Report" for Proposed New Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr), October 16, 2008.

larger units. A natural gas-fired boiler rated at greater than or equal to 75 MMBtu/hr is required to meet 5 ppmvd (at 3 percent O_2) by SCAQMD Rule 1146 and BAAQMD Rule 9-7 (References 12 and 14 in Table D-5). In addition, a NO_x limit of 7 ppmvd (at 3 percent O_2) or less is required as BACT in SCAQMD Guidelines for natural gas or propane-fired boilers rated at ≥20 MMBtu/hr (see Reference 8 in Table D-5) for units with add-on emission controls. Therefore, ARB staff has identified the most stringent NO_x limit as 5 ppmvd (at 3 percent O_2) for natural gas-fired boilers rated at greater than or equal to 20 MMBtu/hr.

2. Control of CO Emissions

CO is a product of incomplete combustion of hydrocarbon-based fuels. Generally speaking, there is an inverse relationship between CO and NO_x – when temperatures are lowered to meet NO_x requirements, the amount of CO increases. All of California is either attainment or unclassified for the State and federal CO ambient air quality standards. However, this is not the case for ozone, as the majority of California air basins are classified as nonattainment. Since NO_x is an ozone precursor, air regulatory programs have focused on maximizing NO_x reductions and have provided more flexible corresponding CO emission levels for combustion sources.

ARB staff noted that some CO requirements were specific to the type of boiler. The three major types of boilers used for natural gas combustion in commercial, industrial, and utility applications are watertube, firetube, and cast iron. Field erected boilers are boilers that are constructed on site and comprise the larger watertube boilers. Generally, boilers with heat input levels greater than 100 MMBtu/hr are field erected. Field erected units usually have multiple burners and, given the customized nature of their construction, also have greater operational flexibility and NO_x control options. Firetube boilers are used primarily for space heating systems, industrial process steam, and portable power boilers; they are almost exclusively packaged units, which are constructed off-site and shipped to the location where they are needed. The physical size of these units is constrained by shipping considerations and generally have heat input levels less than 100 MMBtu/hr. Cast iron boilers are designed similar to firetube boilers but are constructed of cast iron rather than steel.

<u>Boiler Heat Rating 2 to <250 MMBtu/hr</u>
ARB staff found that the CO limits for boilers are consistent up to approximately 250 MMBtu/hr heat input rating. The most stringent CO limits of 50 ppmvd (at 3 percent O_2) for an operational firetube boiler and 100 ppmvd (at 3 percent O_2) for an operational watertube boiler are required as BACT in SCAQMD Guidelines for non-major source facilities (References 5 and 8 in Table D-5). The limits are based on emission levels achieved in practice by units located in the District. These levels are further supported by project-specific BACT requirements (References 3, 10, 11, 13, and 16 in Table D-5). Therefore, ARB staff has identified the most stringent CO limits as 50 ppmvd (at 3 percent O_2) for firetube boilers and 100 ppmvd (at 3 percent O_2) for watertube boilers rated at 2 to less than 250 MMBtu/hr.

Boiler Heat Rating ≥250 MMBtu/hr
The most stringent CO limit for a boiler rated at greater than or equal to 250 MMBtu/hr is 10 ppmvd (at 3 percent O_2). This is deemed technologically feasible BACT in BAAQMD BACT Guideline 17.3.1 and is achievable with add-on controls (e.g., oxidation catalyst). It should be noted that the 10 ppmvd limit may be required for boilers rated at less than 250 MMBtu/hr if an oxidation catalyst is found to be cost effective or is necessary to control TAC or VOC emissions. Therefore, ARB staff has identified the most stringent CO limit as 10 ppmvd (at 3 percent O_2) for boilers greater than or equal to 250 MMBtu/hr.

3. Control of VOC Emissions

Similar to CO emissions, VOC emissions result from incomplete combustion. VOC emissions are released in the exhaust gas when some of the hydrocarbon fuel remains unburned or is partially burned during combustion. Generally, maximizing the time, temperature, and turbulence, provides for more efficient combustion and reduced VOC emissions. Like CO emissions, VOC emissions have traditionally been abated with combustion controls and oxidation catalysts. In addition, due to low VOC concentrations, the control of VOC emissions from natural gas-fired boilers has been less of a priority to regulators than control of NO_x and CO. As a result, initial control of VOC emissions experienced with oxidation catalysts were more coincidental than intentional since the oxidation catalysts were initially utilized to control CO emissions.

ARB staff obtained limited data on VOC emission levels from natural gas-fired boilers. In most cases, district BACT guidelines did not include an evaluation of BACT for VOC emissions or BACT was not triggered. In two cases, BACT for VOC was specified as use of gaseous fuels (References 10 and 15 in Table D-5). In two other project-specific cases, the BACT emission level for VOCs ranged from 0.003 lb/MMBtu to 0.0127 lb/MMBtu (References 3 and 13 in Table D-5). In both cases, no specific emission controls were applied to reduce VOC emissions. U.S. EPA's AP-42, Compilation of Air Pollutant Emission Factors, Table 1.4.2 (July 1998) lists a VOC emission factor of 5.5 lb/MMscf (or 0.005 lb/MMBtu) for natural gas combustion. Due to the limited data set available for this Report, ARB staff has identified the most stringent VOC limit as the emission level corresponding to the use of natural gas fuel for boilers in all heat input ratings, with the specific emission limit determined on a case-by-case basis for a given project. ARB staff recommends that stakeholders consult with the boiler manufacturer on guaranteed emission levels and evaluate VOC emission levels from AP-42, source tests, permits, and any new BACT guidelines or updates in determining the appropriate VOC limit.

4. Control of PM10 Emissions

There are a limited number of options for controlling PM10 emissions from combustion equipment. To date, the only control of boiler exhaust PM10 emissions has been through limiting fuel type and sulfur content. Gaseous fuels are generally associated with the least PM10 emissions due to their lower sulfur, nitrogen, and ash contents.

BACT guidelines in the SCAQMD and BAAQMD specify use of natural gas fuel as BACT for PM10 for boilers in various size ranges (References 5, 8, and 11 in Table D-5). Therefore, ARB staff has identified the most stringent PM10 limit as the emission level corresponding to the use of natural gas fuel for boilers in all heat input ratings.

5. Control of SO_x Emissions

Fuel sulfur is the source of SO_x emissions from boilers fired on gaseous fuels. Since the fuel sulfur content of natural gas is so low, the natural gas odorant substantially contributes to the fuel sulfur content. Since SO_x emissions are highly dependent on fuel sulfur content, the lowest emissions are achieved through the combustion of fuels with the lowest sulfur. Although an applicant can select a low-sulfur fuel, the applicant does not have control of fuel sulfur contents lower than that specified in contracts between gas utilities and gas suppliers. ARB's Guidance for Power Plant Siting and Best Available Control Technology (September 1999), determined that entities regulated by the California Public Utilities Commission have purchase contracts with an effective maximum of total sulfur content for natural gas of 1 grain per 100 standard cubic feet, or 1 gr/100 scf (approximately 17 ppmv sulfur). In addition, some districts have rules specifically limiting the sulfur content of fuels used in stationary sources. For example, SCAQMD Rule 431.1 (last amended June 12, 1998) limits the sulfur content of natural gas to 16 ppmv as hydrogen sulfide (H_2S). Therefore, ARB staff has identified the most stringent SO_x limit as the emission level corresponding to the use of natural gas with a sulfur content of no more than 1 gr/100 scf.

F. Pumps and Compressor Seals

1. Control of VOC Emissions

The most stringent VOC limit for pumps and compressor seals is 100 ppmvd (measured as methane) when measured by U.S. EPA Method 21 (see References 1 and 2 in Table D-8). This is required as technologically feasible BACT in BAAQMD BACT Guideline 137.1 for pumps and Guideline 48B.1 for compressors through use of double mechanical seals with barrier fluid, magnetically coupled pumps, canned pumps, magnetic fluid sealing technology or gas seal system vented to a thermal oxidizer or other approved control device, in connection with a District-approved quarterly inspection and maintenance program. Therefore, ARB staff has identified the most stringent VOC limit as no leak of methane greater than 100 ppmvd in conjunction with the implementation of an inspection and maintenance program that checks for and repairs leaking components. BAAQMD Rule 8-18 and SJVAPCD Rule 4455 can be used as a model.

G. Valves, Flanges, and Other Connectors

1. Control of VOC Emissions

The most stringent VOC limit for valves, flanges, and other connectors is 100 ppmvd (measured as methane) when measured by U.S. EPA Method 21 (see References 1, 2, 3, and 4 in Table D-9). This is required as in the ATC for Reference 1 in Table D-9, and as achieved-in-practice BACT in SJVAPCD Guideline 4.12.1 and BAAQMD BACT Guideline 78.1. Therefore, ARB staff has identified the most stringent VOC limit as no leak of methane greater than 100 ppmvd in conjunction with the implementation of an inspection and maintenance program that checks for and repairs leaking components. BAAQMD Rule 8-18 and SJVAPCD Rule 4455 can be used as a model.

H. Wet Cooling Tower

1. Control of PM10 Emissions

Cooling towers are heat exchangers used to dissipate large heat loads to the atmosphere. There are several types of cooling systems: once-through cooling, wet cooling, dry cooling, and hybrid cooling. Wet cooling has been the usual method of cooling at inland power plants in California and is the focus of discussion here. Because wet cooling towers provide direct contact between the cooling water and air passing through the tower, some of the liquid may be entrained in the air stream and carried out as "drift" droplets. These droplets generally contain the same chemical impurities as the water – therefore the particulate matter constituent of the drift droplets is treated as PM10 emissions.

ARB staff surveyed BACT requirements in districts with the most power plant activity – BAAQMD, SJVAPCD, and SCAQMD. Although BACT is triggered, districts have not required dry cooling as BACT for PM10 emissions from cooling towers. In the BAAQMD, power plant BACT for cooling has been based on a wet system equipped with drift eliminators with a drift rate of 0.0005 percent of circulating water flow (Reference 2 in Table D-10). A cooling tower may be exempt from permit if it is not used for evaporative cooling of process water (water containing organics), it passes risk screening, and emits no more than 5 tons per year (tpy). The 5-tpy threshold was added in May 2000.[8] Prior to that, power plant cooling towers were exempt from permit. In the SJVAPCD, District BACT Guideline 8.3.10 specifies technologically feasible PM10 BACT for an induced draft evaporative cooling tower as a cellular type drift eliminator (Reference 1 in Table D-10).

In the SCAQMD, cooling towers are exempt from permit unless they use contaminated water. If the cancer risk exceeds 1-in-a-million or hazard indices exceed 1.0, the exemption does not apply. Several contemporary combined-cycle power plant projects have not exceeded the District's risk thresholds and have been exempt from permit, so BACT and offsets have been not been required by the District. However, emission calculations are consistent with use of drift eliminators with a drift rate of 0.0005 percent of circulating water flow (Reference 3 in Table D-10). In addition, ARB staff found BACT determinations for cooling towers used at ethanol plants in the Midwest that also require use of drift eliminators with a drift rate of 0.0005 percent (References 4 and 5 in Table D-10). Therefore, ARB staff has identified the most stringent PM10 limit as the

[8] Per BAAQMD Rule 2-1-319.1 (last amended March 4, 2009).

emission level corresponding to use of a drift eliminator with 0.0005 percent drift loss for wet cooling towers.

I. Natural Gas-Fired Dryer

1. Control of NO_x Emissions

The most stringent NO_x limit for a natural gas-fired dryer is 15 ppmvd at 3 percent O_2 (or 0.018 lb/MMBtu). This NO_x limit is identified as technologically feasible BACT in SJVAPCD Guideline 4.12.6 (Reference 2 in Table D-16). The limit is achievable with ultra low-NO_x burners. Therefore, ARB staff has identified the most stringent NO_x limit as 15 ppmvd at 3 percent O_2 for natural gas-fired dryers.

2. Control of CO Emissions

The most stringent CO limit for a natural gas-fired dryer used at a biorefinery is 0.07 lb/MMBtu and is required in the permit for Reference 5 in Table D-16. At this facility, the dryer shares its exhaust stack with a biomass boiler. The next most stringent CO limit of 0.104 lb/MMBtu (approximately 141 ppmvd at 3 percent O_2) is required in the permit for Reference 4 in Table D-16. The emission control technology is not specified in the permit information received by ARB staff, and no corresponding source tests were available. Therefore, while ARB staff has identified the most stringent CO limit as 0.07 lb/MMBtu for natural gas-fired dryers, regulatory agencies should evaluate the feasibility of this limit for specific applications due to the limited amount of information available at the time of this Report.

3. Control of VOC Emissions

The most stringent VOC limit for a natural gas-fired dryer is an emission limit corresponding to use of a VOC capture and control system with thermal or catalytic incineration or equivalent (98 percent control). This is identified as achieved-in-practice BACT in SJVAPCD Guideline 4.12.6 (Reference 2 in Table D-16). Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to use of a VOC capture and control system with thermal or catalytic incineration or equivalent (98 percent control) for natural gas-fired dryers.

4. Control of PM10 Emissions

The most stringent PM10 limit for a natural gas-fired dryer is an emission limit corresponding to use of high efficiency (1D-3D) cyclones and thermal incinerator in series or equivalent (98.5 percent control). This is identified as achieved-in-practice BACT in SJVAPCD Guideline 4.12.6 (Reference 2 in Table D-16). Therefore, ARB staff has identified the most stringent PM10 limit as the emission level corresponding to use of high efficiency (1D-3D) cyclones and thermal incinerator in series or equivalent (98.5 percent control) for natural gas-fired dryers.

5. Control of SO_x Emissions

The most stringent SO_x limit for a natural gas-fired dryer is an emission limit corresponding to use of a wet scrubber (95 percent control). This is identified as technologically feasible BACT in SJVAPCD Guideline 4.12.6 (Reference 2 in Table D-16). Therefore, ARB staff has identified the most stringent SO_x limit as the emission level corresponding to use of a wet scrubber (95 percent control) for natural gas-fired dryers.

J. Storage Tanks (Fixed Roof)

The most stringent VOC limit for a fixed roof storage tank is an emission level corresponding to the use of a VOC control system with 99.5 percent control efficiency. This is required in the ATC for Reference 1 in Table D-14. The control efficiency can be met with the use of vapor recovery routed to a distillation column and two-stage vapor condenser. The next most stringent VOC limit is an emission level corresponding to the use of a VOC control system with 99 percent control efficiency and is required as technologically feasible BACT in SJVAPCD Guideline 7.3.1 (Reference 2 in Table D-14). This guideline pertains to petroleum production, but could be applied as a technology transfer to a biorefinery. Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to the use of a VOC control system capable of 99.5 percent or better control efficiency.

K. Storage Tanks (Floating Roof)

1. Control of VOC Emissions

The most stringent VOC limit for an external or internal floating roof storage tank is an emission level corresponding to the use of a VOC control system with 98 percent control efficiency. This is required as technologically feasible BACT in BAAQMD Guideline 167.1.1 and Guideline 167.4.1 (Reference 1 in Table D-15). The control efficiency can be met by routing tank vapors to a thermal incinerator, carbon adsorber, refrigerated condenser, or District-approved equivalent technology. Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to the use of a VOC control system capable of 98 percent or better control efficiency.

L. Flare (Ethanol Production)

1. Control of NO_x Emissions

The most stringent NO_x limit for a flare used in ethanol production is 0.05 lb/MMBtu. This NO_x limit is required in the permit for Reference 3 in Table D-13 and is achievable with a low-NO_x burner. The next most stringent NO_x limit of 0.068 lb/MMBtu (approximately 56 ppmvd at 3 percent O_2) is contained in the permits for References 5 and 6 in Table D-13 for both air assist and enclosed flares. Therefore, ARB staff has identified the most stringent NO_x limit as 0.05 lb/MMBtu for loadout flares used in ethanol production.

2. Control of CO Emissions

The most stringent CO limit for a loadout flare used in ethanol production is 0.37 lb/MMBtu. This CO limit is required in the permits for References 5 and 6 in Table D-13 and is achievable for both air assist and enclosed flares. ARB staff was not able to acquire corresponding source tests for these or any other comparable sources. ARB staff noted that the corresponding CO limit for the flare with the 0.05 lb/MMBtu NO_x limit (see NO_x discussion above) is more than double the CO limit for the flares with the 0.068 lb/MMBtu NO_x limits. ARB staff assumes this could be due to the use of low-NO_x burners to meet the 0.05 lb/MMBtu NO_x limit and the inverse relationship between NO_x and CO combustion emissions. Without the benefit of source test data, ARB staff has some concerns about the ability to meet the 0.05 lb/MMBtu NO_x limit in conjunction with a 0.37 lb/MMBtu CO limit. Therefore, while ARB staff has identified the most stringent CO limit as 0.37 lb/MMBtu for loadout flares used in ethanol production, ARB staff acknowledges that regulatory agencies could consider a higher CO limit as a trade-off for a lower NO_x limit, especially in ozone nonattainment areas and in cases where BACT for CO is not triggered.

3. Control of VOC Emissions

The most stringent VOC limit for a loadout flare used in ethanol production is 0.063 lb/MMBtu. This VOC limit is required in the permits for References 5 and 6 in Table D-13 and is achievable for both air assist and enclosed flares. Therefore, ARB staff has identified the most stringent VOC limit as 0.063 lb/MMBtu for loadout flares used in ethanol production.

4. Control of PM10 Emissions

The most stringent PM10 limit for a loadout flare used in ethanol production is 0.008 lb/MMBtu. This PM10 limit is required in the permit for Reference 5 in Table D-13. Therefore, ARB staff has identified the most stringent PM10 limit as 0.008 lb/MMBtu for loadout flares used in ethanol production.

5. Control of SO_x Emissions

The most stringent SO_x limit for a loadout flare used in ethanol production is 0.00285 lb/MMBtu. This SO_x limit is required in the permit for Reference 5 in Table D-13. Therefore, ARB staff has identified the most stringent SO_x limit as 0.00285 lb/MMBtu for loadout flares used in ethanol production.

M. Liquid Fuel Loading Operations

1. Control of VOC Emissions

The most stringent VOC limit for liquid fuel loading operations is an emission level corresponding to the use of a VOC control system with 98 percent control efficiency. This is required in the permit for Reference 4 in Table D-18. The control efficiency can be met with a carbon adsorption canister. Other permits for ethanol loading and unloading operations require the use of a carbon adsorber to reduce VOC emissions, along with maximum leak rates (References 3 and 5 in Table D-18). Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to the use of a VOC control system capable of 98 percent or better control efficiency.

N. Liquid Fuel Transfer and Dispensing Operations

1. Control of VOC Emissions

ARB is responsible for certifying vapor recovery systems used at gasoline service stations, bulk plants, terminals, cargo tanks, and novel facilities. In the process of certifying vapor recovery systems, ARB establishes performance standards and specifications for systems and their components. Districts have the primary responsibility of regulating emissions from stationary sources such as gas stations. To this end, districts have adopted rules that require gasoline storage and transfer operations to be equipped with vapor recovery systems certified by ARB.

Vapor recovery systems collect gasoline vapors that would otherwise escape into the atmosphere during fuel delivery to the underground storage tanks (Phase I) or fuel storage and vehicle fueling (Phase II). ARB staff assumes that district rules requiring vapor recovery equipment are applicable to biofuel blends that meet the definition of "gasoline" as defined in district rules (generally these definitions pertain to the vapor pressure of the fuel). ARB has certified a number of Phase I and II systems for gasoline. However, a biofuel blend such as E-85 requires a separate certification. To date, ARB has certified an E-85 compatible Phase I vapor recovery system designed for use with underground storage tanks. ARB has not certified a Phase I E-85 for aboveground tanks or a Phase II E-85 system for underground or aboveground tanks. This is reflected in SCAQMD Rule 461 which exempts E-85 from Phase II requirements until April 1, 2012 (Reference 1 in Table D-20). The Phil-Tite Phase I system, which is ARB certified, is required. Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to use of an ARB certified Phase I vapor recovery system to reduce VOC emissions from liquid fuel transfer and dispensing operations using biofuel blends that are subject to local district requirements.

O. Biomass-Fired Boilers

ARB staff found that biorefineries that require heat or steam for the production process almost exclusively use natural gas-fired boilers. However, staff did locate one cellulosic ethanol plant in California that proposed to use an 85 MMBtu/hr (approximately 25 MW) biomass (lignin)-fired boiler. Therefore, although not commonplace, ARB staff has included biomass-fired boilers as a category of equipment that may be used at biorefineries. ARB staff noted that emission standards for biomass boilers were typically bifurcated at the 10 to 25 MW boiler rating level. Since ARB staff expects biomass boilers used in biofuel production to be rated at greater than 10 MW, this section evaluates the emission limits for units of this size. However, Appendix D includes some data on biomass boilers less than 10 MW for informational purposes.

1. Control of NO_x Emissions

The most stringent NO_x limit for a biomass-fired boiler is 0.012 lb/MMBtu (approximately 9 ppmvd at 3 percent O_2). This limit was determined to be technologically feasible BACT in the ATC for a 402 MMBtu/hr (33 MW) biomass boiler with a Detroit stoker vibrating grate feeder (Reference 6 in Table D-6) and will be achieved using selective non-catalytic reduction (SNCR), SCR, wet scrubber, and natural gas auxiliary fuel. This limit is also consistent with technologically feasible BACT guidance from the Massachusetts Department of Environmental Protection (MDEP). MDEP's BACT Guidance for Biomass Projects dated April 18, 2007, for biomass-fired boilers rated at 10 MW or greater recommends a NO_x limit of 0.015 lb/MMBtu (approximately 12 ppmvd at 3 percent O_2).

The next most stringent NO_x limit for an operational biomass-fired boiler is 0.075 lb/MMBtu (approximately 58 ppmvd at 3 percent O_2). This NO_x limit is deemed achieved in practice BACT by the SJVAPCD and MDEP (References 4 and 7 in Table D-6). The limit was also required as BACT in the permit for Reference 3 in Table D-6. The achievability of the limit was substantiated in source tests for References 11 and 12 in Table D-6. All of the referenced boilers employ a circulating fluidized bed and are equipped with SNCR for NO_x control.

Therefore, ARB staff has identified the most stringent NO_x limit as 0.012 lb/MMBtu for biomass-fired boilers.

2. Control of CO Emissions

The most stringent CO limit for a biomass-fired boiler is 0.01 lb/MMBtu (approximately 13 ppmvd at 3 percent O_2). This limit is categorized as technologically feasible BACT in the MDEP's BACT Guidance for Biomass Projects dated April 18, 2007, for biomass-fired boilers rated at 10 MW or greater. The CO limit is based on applying an oxidation catalyst and the assumption that the same level of emission reduction that has been achieved on other fuel sources will be achieved using biomass fuels. The Guidance states that the agency considers this a starting point for a BACT analysis and will consider alternative limits if the applicant can demonstrate that the limit is not technically feasible.

The next most stringent CO limit for a biomass-fired boiler is 0.046 lb/MMBtu (approximately 59 ppmvd at 3 percent O_2). This limit was determined to be technologically feasible BACT in the ATC for a 402 MMBtu/hr (33 MW) biomass boiler with a Detroit stoker vibrating grate feeder (Reference 6 in Table D-6) and will be achieved using an oxidation catalyst and good combustion practices. It should be noted that, although BACT was not triggered, the oxidation catalyst was proposed by the applicant.[9] Therefore, this reflects an achievable permit limit based on the equipment and add-on controls proposed for this project; it does not reflect a project-specific BACT analysis for CO.

Available permit data for existing biomass boilers in California and information from Babcock & Wilcox Power Generation Group[10] indicates CO emissions from circulating fluidized-bed (CFB) boilers are lower than stoker boilers. Therefore, for example, because the baseline exhaust CO emissions from a stoker boiler are higher than from a CFB boiler, applying an oxidation catalyst that achieves an 80 percent reduction will still result in higher CO stack emissions from the stoker unit. With the exception of CO, the most stringent limits for all other pollutants identified by ARB staff for biomass-fired boilers come from a stoker boiler at a single facility (Reference 6 in Table D-6). Due to different expected emissions performance results based on boiler firing technology, ARB staff believes we do not have sufficient data at the drafting of this Report to determine that the most stringent CO limit of 0.01 lb/MMBtu is achievable in conjunction with the other pollutant limits. Therefore, ARB staff has identified the most stringent CO limit as 0.046 ppmvd (at 3 percent O_2) for biomass-fired boilers. However, ARB staff also recommends that regulatory agencies evaluate the feasibility of meeting a CO limit of 0.01 lb/MMBtu, particularly if the applicant is proposing a new CFB-type boiler.

3. Control of VOC Emissions

The most stringent VOC limit for a biomass-fired boiler is 0.005 lb/MMBtu (approximately 11 ppmvd as CH_4 at 3 percent O_2). This limit was determined to be technologically feasible BACT in the ATC for a 402 MMBtu/hr (33 MW) biomass boiler with a Detroit stoker vibrating grate feeder (Reference 6 in Table D-6) and will be achieved using an oxidation catalyst, good combustion practices, and natural gas auxiliary fuel. Therefore, ARB staff has identified the most stringent VOC limit as 0.005 lb/MMBtu for biomass-fired boilers.

4. Control of PM10 Emissions

The most stringent PM10 limit for a biomass-fired boiler is 0.024 lb/MMBtu (approximately 0.01 gr/dscf at 12 percent CO_2). This limit was determined to be technologically feasible BACT in the ATC for a 402 MMBtu/hr (33 MW) biomass boiler with a Detroit stoker vibrating grate feeder (Reference 6 in Table D-6) and will be achieved using a multiclone and electrostatic precipitator (ESP).

[9] In SJVAPCD, BACT for CO is triggered if the potential to emit exceeds 2.0 lbs/day and the facility-wide potential to emit is 200,000 lbs/yr or greater.
[10] Babcock & Wilcox Power Generation Group, Inc. publication, *Bubbling Fluidized-Bed Boilers: Burning Biomass and Low-Cost Fuels*, 2008, http://www.babcock.com/library/pdf/E1013161.pdf.

Available permit data for existing biomass boilers in California shows these units are equipped with various types of particulate control devices including multiclones, baghouses, and ESPs. Permitted limits range from 0.01 to 0.2 gr/dscf (at 12 percent CO_2). The PM10 emission values most likely vary because of differing sampling methods used. Available data indicate the highest level of PM10 control is from an ESP. Facilities equipped with ESPs have source test data demonstrating PM10 emissions as low as 0.0005 gr/dscf (at 12 percent CO_2) (0.001 lb/MMBtu) as shown in the source test for Reference 12 in Table D-6.

While the source test methods used report emissions as PM10 or total solid particulates, ARB PM size fraction data indicates 99.7 percent of emissions from combustion in a wood-fired boiler is PM10 or less. Available data also indicate that units can meet a total (filterable and condensable) PM10 limit of 0.01 gr/dscf (see References 10, 12, and 13 in Table D-6). Therefore, ARB staff has identified the most stringent PM10 limit as 0.01 gr/dscf at 12 percent CO_2 or 0.024 lb/MMBtu for biomass-fired boilers.

5. Control of SO_x Emissions

The most stringent SO_x limit for a biomass-fired boiler is 0.012 lb/MMBtu (approximately 7 ppmvd at 3 percent O_2). This limit was determined to be technologically feasible BACT in the ATC for a 402 MMBtu/hr (33 MW) biomass boiler with a Detroit stoker vibrating grate feeder (Reference 6 in Table D-6) and will be achieved using trona injection and natural gas auxiliary fuel. The SJVAPCD determined that trona injection provides SO_x control at least equivalent to limestone injection. Therefore, ARB staff has identified the most stringent SO_x limit as 0.012 lb/MMBtu for biomass-fired boilers.

P. Landfill Gas-Fired Flare

a. Control of NO_x Emissions

The most stringent NO_x limit for a landfill gas-fired flare is 0.025 lb/MMBtu. This NO_x limit is listed as BACT in SCAQMD BACT Guidelines Part B (Reference 5 in Table D-11) for an enclosed flare. Therefore, ARB staff has identified the most stringent NO_x limit as 0.025 lb/MMBtu for landfill gas-fired flares.

b. Control of CO Emissions

The most stringent CO limit for a landfill gas-fired flare is 0.06 lb/MMBtu. This CO limit is listed as BACT in SCAQMD BACT Guidelines Part B (Reference 5 in Table D-11) for an enclosed flare. Therefore, ARB staff has identified the most stringent CO limit as 0.06 lb/MMBtu for landfill gas-fired flares.

c. Control of VOC Emissions

The most stringent VOC limit for a landfill gas-fired flare is 98 percent destruction efficiency or 20 ppmvd at 3 percent O_2. This VOC limit is listed as BACT in SCAQMD BACT Guidelines Part B (Reference 5 in Table D-11) for an enclosed flare. It is also listed as achieved-in-practice BACT in SJVAPCD Guideline 1.4.3 (Reference 2 in Table D-11). Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to 98 percent destruction efficiency or 20 ppmvd at 3 percent O_2 for landfill gas-fired flares.

d. Control of PM10 Emissions

The most stringent PM10 limit for a landfill gas-fired flare is an emission limit corresponding to use of steam injection and/or knockout vessel. Use of steam injection is listed as technologically feasible BACT in SJVAPCD Guideline 1.4.3 (Reference 1 in Table D-11) for an enclosed flare. Use of an external force such as steam injection or blowing air is used for efficient air/waste gas mixing which promotes smokeless flaring. Use of a knockout vessel is listed as BACT in SCAQMD BACT Guidelines for Non-Major Facilities (Reference 3 in Table D-11). Liquid in the process gas stream can extinguish the flame or cause irregular combustion and smoking. A knockout vessel is located at the base of the flare or inside the base of the flare stack and is used to remove liquids in the gas stream. Therefore, ARB staff has identified the most stringent PM10 limit as the emission level corresponding to use of steam injection and/or knockout vessel for landfill gas-fired flares.

e. Control of SO_x Emissions

The most stringent SO_x limit for a landfill gas-fired flare is an emission limit corresponding to use of a wet scrubber with 98 percent control efficiency. This is listed as technologically feasible BACT in SJVAPCD Guideline 1.4.3 (Reference 1 in Table D-11) for an enclosed flare. Therefore, ARB staff has identified the most stringent SO_x limit as the emission level corresponding to use of a wet scrubber with 98 percent control efficiency for landfill gas-fired flares.

Q. Manure Digester and Co-Digester Gas-Fired Flare

1. Control of NO_x Emissions

The most stringent NO_x limit for a digester gas-fired flare is 0.03 lb/MMBtu. This NO_x limit is listed as technologically feasible BACT in SJVAPCD Guideline 1.4.4 for a digester gas-fired flare equipped with ultra low-NO_x burners (Reference 1 in Table D-12). The limit is also required as technologically feasible BACT in SJVAPCD Guideline 2.2.3 for a cheese wastewater-fired flare using ultra low-NO_x burners. Therefore, ARB staff has identified the most stringent NO_x limit as 0.03 lb/MMBtu for digester gas-fired flares.

2. Control of CO Emissions

ARB staff was unable to obtain any specific information regarding CO emissions performance for digester gas-fired flares. The most stringent CO requirement staff found for a digester gas-fired flare is operation of the flare per manufacturer specifications to minimize CO. This is listed as achieved-in-practice BACT in SJVAPCD Guideline 1.4.4 for a digester gas-fired enclosed flare (Reference 2 in Table D-12). However, ARB staff expects that digester gas-fired flares should be able to achieve comparable CO emissions as the other flares listed in this Report. Therefore, ARB staff recommends a CO limit of consistent with operation of the flare per manufacturer specifications to minimize CO for digester gas-fired flares.

3. Control of VOC Emissions

The most stringent VOC limit for a digester gas-fired flare is 0.03 lb/MMBtu and is required as technologically feasible BACT in SJVAPCD Guideline 1.4.6 for a biogas-fired limited use flare (Reference 3 in Table D-12). The next most stringent VOC limit is 0.068 lb/MMBtu. This VOC limit is listed as achieved-in-practice BACT in SJVAPCD Guideline 1.4.4 for a digester gas-fired enclosed flare (Reference 2 in Table D-12). Therefore, ARB staff has identified the most stringent VOC limit as 0.03 lb/MMBtu for digester gas-fired flares. However, regulatory agencies should assess whether the limited use flare constitutes a different class or category of source for purposes of determining the lowest feasible VOC emission level for their particular flare application.

4. Control of PM10 Emissions

The most stringent PM10 limit for a digester gas-fired flare is an emission limit corresponding to use of smokeless combustion and an liquefied petroleum gas (LPG) or natural gas-fired pilot. A smokeless flare uses compressed air that is pumped into the flame and burning gas, using a special nozzle system. The air/waste gas mixing improves combustion and reduces smoking. This is listed as achieved-in-practice BACT in SJVAPCD Guideline 1.4.4 for a digester gas-fired enclosed flare and as technologically feasible BACT in SJVAPCD Guideline 2.2.3 for a cheese wastewater-fired enclosed flare (References 1 and 4 in Table D-12). Therefore, ARB staff has identified the most stringent PM10 limit as the emission level corresponding to use of smokeless combustion and an LPG or natural gas-fired pilot for digester gas-fired flares.

5. Control of SO_x Emissions

The most stringent SO_x limit for a digester gas-fired flare is an emission limit corresponding to use of an H_2S removal system (dry or wet scrubber or equivalent). this is listed as technologically feasible BACT in SJVAPCD Guideline 1.4.4 for a digester gas-fired flare and Guideline 2.2.3 for a cheese wastewater-fired flare (References 1 and 4 in Table D-12). Therefore, ARB staff has identified the most stringent SO_x limit as the emission level corresponding to use of an H_2S removal system (dry or wet scrubber or equivalent) for digester gas-fired flares.

R. Compressed Gas Dispensing Operations

ARB staff identified permits for two compressed gas dispensing operations. The operations consist of biogas treating, compression, and dispensing equipment to collect and treat landfill gas to produce CNG for vehicles. At both facilities, there are no direct emissions associated with the equipment. These are closed loop systems with all vent and excess process gas being directed to the on site treatment system, used in vehicles, or directed to another combustion (e.g., flare) or processing facility that can process the biogas and which has been issued a valid district permit.

S. Combustion of Biomethane

In this Report, the term "biomethane" refers to biogas produced by anaerobic digestion that has been comprehensively treated to remove impurities. Typical sources of biomethane include biosolids, manure, and food waste digesters; and landfills. The term "biogas" is used to refer to gas that has not been subject to comprehensive treatment.

ARB staff has found that production of biofuels for transportation from anaerobic digestion is a co-product of a larger system put in place to manage a waste stream such as at a landfill, wastewater treatment plant, or dairy. This section is intended to address emissions from the point where the biogas from anaerobic digestion has been treated to remove impurities. Therefore, this section does not identify or recommend emission limits for any stationary source pollutant-emitting equipment *prior* to the combustion of the biomethane to generate electricity or produce transportation fuels.

ARB staff found that facilities that use biomethane for transportation fuels may also use a portion of the biomethane for energy production in reciprocating internal combustion engines or turbines. Additional excess biogas is generally flared. Fuel cells can also be used to produce energy from biomass. The emissions performance of these types of electrical generating units, as well as flares, is addressed below.

1. Biogas Treatment

Biogas created from the anaerobic digestion of biomass is typically composed of about 50 percent CH_4, 50 percent CO_2, very small amounts of non-methane organic compounds, and other contaminants. Due to the adverse effects of biogas contaminants, gas treatment is required prior to use in a fuel cell, boiler, reciprocating IC engine, or turbine. Contaminants found in biogas include H_2S and a variety of other corrosive gases from chemical products in the waste. Sewage digester and landfill gas also contain siloxanes, which are silica-based compounds from various consumer products in the waste stream. Some of the specific components of waste and biogas and their operational challenges include:

- Solids, which can cause erosion of critical surfaces or plugging of orifices.

- Water, which retards combustion and can cause erosion, corrosion, or catastrophic damage to critical surfaces or components.
- Non-methane fuel components (butane, propane, CO, hydrogen), which can change combustion characteristics; if present in liquid form can cause physical damage.
- Sulfur and sulfur compounds, which can cause corrosion in engines, increase maintenance requirements (more frequent overhauls and oil changes), and poison catalytic materials.
- CO_2, which reduces heating value and combustibility.
- Siloxanes, which create a glassy deposition on high-temperature surfaces; particles can break off and damage working parts.

Typical treatments remove moisture, CO_2, sulfur compounds, particulates, and other impurities. Siloxane removal is typically accomplished with adsorption beds. Additional treatment technologies that have been applied to oil field and landfill gas should be evaluated for feasibility to transfer to other types of biogas. These use a variety of gas separation technologies that rely upon physical, biological, and/or chemical filtration.

2. Distributed Generation Subject to ARB Certification (NO_x, CO, and VOC Emission Standards)

Distributed Generation (DG) refers to electrical generation near the place of use. In California, every DG unit must be certified by the ARB or permitted by a local district. Permit exemption levels vary among California's 35 air districts; although permitting thresholds tend to be low, especially in non-attainment areas. Therefore, DG subject to the ARB's certification program tend to be small generating units. Examples of the technologies typically subject to the DG certification program include microturbines up to 250 kW, reciprocating IC engines under 50 brake horsepower (bhp), external combustion engines, and fuel cells. Biomass-fueled DG equipment typically operate on biogas. Detailed information on ARB's DG Certification Program can be found at http://www.arb.ca.gov/energy/dg/dg.htm.

The DG Program specifies emission standards for NO_x, CO, and VOC. Table V-1 summarizes the ARB's DG certification emission standards for waste gas-fired units[11]. The 2013 standards represent BACT for natural gas-fired central station power plants. These reflect the directive of the enabling legislation, Senate Bill 1298, which required that DG equipment in California must meet central station power plant emission standards "at the earliest practicable date." DG units that produce combined heat and power (CHP) may take advantage of a credit to meet the 2013 standards.

[11] Waste gases, as defined in the regulation, include gases produced from the decomposition of sewage, gases produced from the decomposition and volatilization of materials in landfills, and gases produced from the drilling of oil wells and pumping of oil from wells that are not eligible for delivery to the utility pipeline system.

Table V-1. Waste Gas Emissions Standards for DG Certified by ARB

Pollutant	Emission Standard (lb/MW-hr)	
	On or after January 1, 2008	On or after January 1, 2013
NO_x	0.5	0.07
CO	6.0	0.10
VOC	1.0	0.02

a. Fuel Cells

A fuel cell is an electrochemical device that combines hydrogen with oxygen to produce electricity, heat, and water. The hydrogen can be supplied through a tank or a reformer that extracts the hydrogen from a fossil fuel, such as natural gas. Although no companies that produce waste gas fuel cell technologies have requested certification by ARB, available data shows that the technology is able to meet the 2013 NO_x and CO standards. In the two available source tests for VOC, one site met the 2008 standard and the other met the 2013 standard. Source tests demonstrating compliance with the emission standards are given in References 3, 5, and 6 in Table D-7 for units using landfill and sewage digester gas.

Because the performance of currently operating fuel cells is well below the January 1, 2008 emission standards, ARB staff recommends that regulatory agencies consider the 2013 limits of 0.07 lb/MWh NO_x, 0.10 lb/MWh CO, and 0.02 lb/MWh VOC for biomethane-fueled fuel cells. In no event should the limits for biomethane fuel cells exceed 0.5 lb/MWh NO_x, 6.0 lb/MWh CO, and 1.0 lb/MWh VOC.

b. Microturbines

California air districts typically require a permit for gas turbines as small as 300 kW. Microturbines are high-speed, single-rotor turbines that are usually less than 300 kW in size. They can operate alone or in parallel with a number of units.

To date, the ARB has issued six certifications for waste gas applications. These include a 65 kW Capstone CR65 microturbine using both landfill and sewage digester gas, a 250 kW Ingersoll Rand 250SW microturbine using landfill gas, a 250 kW Ingersoll Rand 250ST microturbine using sewage digester gas, a 65 kW Capstone C65 High Btu microturbine using oil field gas, and a 250 kW Capstone CR200 Medium Btu microturbine using sewage digester gas. The units are certified to comply with the 2008 DG waste gas emission standards in Table V-1. Emission data showing compliance with the standards for waste gas is included as References 1, 2, 3, and 4 in Table D-21. The composition of the surrogate sewage digester gas used for the certification is 60 to 65 percent CH_4 and 35 to 40 percent CO_2 by volume, which is similar to manure digester gas. The presence of other contaminants is only expected to affect the type of gas pretreatment required (e.g., siloxane removal from sewage digester gas and likely more H_2S removal from manure digester gas).

Experience to date with microturbines run on dairy biomethane indicates the most common problem is compressor failure. Compressors are separate equipment, but are required to increase the biomethane to the required pressure for operation of the microturbines. It appears that the cause of compressor failure is lack of biomethane pretreatment to remove H_2S and moisture. Therefore, the acceptable level of H_2S to prevent compressor failure needs to be determined for each application.

Consistent with the DG Certification Program, ARB staff recommends limits of 0.5 lb/MWh NO_x, 6.0 lb/MWh CO, and 1.0 lb/MWh VOC for biomethane-fired microturbines. On and after January 1, 2013, ARB staff recommends limits of 0.07 lb/MWh NO_x, 0.10 lb/MWh CO, and 0.02 lb/MWh VOC for biomethane-fired microturbines

3. Distributed Generation Requiring District Permit

a. Reciprocating IC Engines

i. Control of NO_x Emissions

The most stringent NO_x limit for a landfill- or digester gas-fired reciprocating IC engine is 11 ppmvd at 15 percent O_2. This NO_x limit is required by SCAQMD Rule 1110.2, effective July 1, 2012. When Rule 1110.2 was amended in 2008 to include this limit for waste gas-fired reciprocating IC engines, the rule called for a Technology Assessment by July 2010 to verify the feasibility of available control technologies.[12] On July 9, 2010, the SCAQMD issued an Interim Report on Technology Assessment for Biogas Engines Subject to Rule 1110.2, which summarizes District staff's technology assessment and findings to date, including the status of three on-going demonstration projects, which experienced significant delays due to the permit moratorium in 2009, and will be followed by another report upon completion of the technology demonstration projects. While the evidence collected to date demonstrates the potential feasibility of the emission limits for biogas reciprocating IC engines, the delay in implementing the demonstration projects will likely necessitate an adjustment to the July 1, 2012, compliance date in the rule. An adjustment to the effective date will be handled through a formal rulemaking that would be initiated in the second half of 2010.

Landfill Gas

The second most stringent NO_x limit for an operational landfill gas-fired reciprocating IC engine is 0.5 g/bhp-hr. This NO_x limit is required in the permit for Reference 7 in Table D-22 using lean-burn/turbocharged engine technology. Several source tests demonstrating compliance with the NO_x limit at this site are included in Appendix D, Table D-22. However, past source test data indicates there have been some problems meeting the NO_x, CO, and VOC permit limits. The third most stringent NO_x limits of 0.5 and 0.6 g/bhp-hr for landfill gas-fired reciprocating IC engines are contained in the permits for References 4, 20, 21, 22, 24, 26, and 27 in Table D-22. Additional source tests show compliance with the 0.5 and 0.6 g/bhp-hr emission levels, and are available

[12] Rule 1110.2 establishes emission limits for NOx, CO, and VOC.

in Table D-22.

Sewage Digester Gas
The second most stringent NO_x limit for an operational sewage digester gas-fired reciprocating IC engine is 0.5 g/bhp-hr. This NO_x limit is required in the permit for Reference 7 in Table D-23 using lean-burn, turbocharged, and aftercooled engine technology. Three source tests demonstrating compliance with the NO_x limit at various wastewater treatment plants are included in Appendix D, Table D-23. The third most stringent NO_x limit of 0.6 g/bhp-hr is contained in the permits for References 3 and 4 in Table D-23.

Manure Digester and Co-Digester Gas
Dairy manure digester and co-digester gas-fired reciprocating IC engines triggering BACT requirements in the San Joaquin Valley have been required to meet a NO_x BACT limit consistent with SCAQMD Rule 1110.2. The SJVAPCD currently considers a NO_x limit of 0.15 g/bhp-hr as BACT for dairy digester gas-fired reciprocating IC engines. Depending on efficiency assumptions, this is equivalent to approximately 9 to 11 ppmvd at 15 percent O_2. The District is currently using 9 ppmvd as BACT for rich-burn reciprocating IC engines and 11 ppmvd as BACT for lean-burn reciprocating IC engines. The NO_x limit of 9.0 ppmvd at 15 percent O_2 is required in the permit for a dairy manure and cheese waste rich burn digester gas-fired reciprocating IC engine (Reference 7 in Table D-24). A recent source test demonstrated compliance with 9.0 ppmvd at 15 percent O_2 (Reference 8 in Table D-24). The NO_x limit of 11.0 ppmvd at 15 percent O_2 is required in the ATC for a dairy digester gas-fired reciprocating IC engine (Reference 2 in Table D-24) using lean-burn technology and SCR. The lean-burn engine permit includes a 24-month trial period to reduce NO_x to the target 0.15 g/bhp-hr. The final NO_x BACT limit will be determined by the District after 24 months of operating history, but in no way can exceed 0.60 g/bhp-hr.

The second most stringent NO_x limit for an operational dairy manure digester gas-fired reciprocating IC engine is 47 ppmvd (at 15 percent O_2) or 0.9 g/bhp-hr (Reference 4 in Table D-24). The ARB's July 2002 Guidance for the Permitting of Electrical Generation Technologies (DG BACT Guidance) recommended 0.6 g/bhp-hr (50 ppmvd at 15 percent O_2) as BACT for NO_x from waste gas-fired reciprocating IC engines (Reference 3 in Table D-22). BAAQMD achieved-in-practice BACT guidance requires 0.5 to 0.6 g/bhp-hr as BACT for NO_x from landfill gas-fired reciprocating IC engines greater than 250 bhp using lean-burn technology (References 29 and 30 in Table D-22). BAAQMD achieved-in-practice BACT guidance requires 0.5 to 0.6 g/bhp-hr as BACT for NO_x from landfill gas-fired reciprocating IC engines greater than 250 bhp using lean-burn technology (References 29 and 30 in Table D-22)

The combination of permit limits and source test data in Appendix D for waste gas-fired reciprocating IC engines indicate NO_x levels of 36 ppmvd (at 15 percent O_2) or less are achievable for waste gas derived from landfills, wastewater treatment plants, and dairy digesters. The additional source test from a co-digester gas-fired engine demonstrates that even lower levels can be achieved with post-combustion, add-on emission controls.

The corresponding g/bhp-hr limits vary based on the efficiency of each engine (from 0.2 to 0.6 g/bhp-hr). In addition, the initial results of the SCAQMD Rule 1110.2 Technology Assessment have found that two approaches appear capable of achieving compliance with the rule limits: (1) application of SCR for NO_x reduction and catalytic oxidation of CO and VOC together with biogas treatment upstream of the engine to remove catalyst fouling impurities and (2) application of a non-catalytic technology known as NO_xTech that reduces NO_x, VOC, and CO. Therefore, ARB staff has identified the most stringent NO_x limit as 11 ppmvd at 15 percent O_2 (or 0.15 g/bhp-hr)[13], and staff recommends that this limit be evaluated as a technologically feasible NO_x emission limit for all digester and landfill gas reciprocating IC engines in conjunction with an effective and efficient biogas treatment system.

ii. Control of CO Emissions

Landfill Gas
The most stringent CO limit for an operational landfill gas-fired reciprocating IC engine is 0.3 g/bhp-hr (approximately 37 ppmvd at 15 percent O_2). This CO limit is required in the permit for Reference 4 in Table D-22. ARB staff found two source tests demonstrating compliance with this CO limit (References 5 and 25 in Table D-22). However, several other source tests show much higher CO emission levels. The next most stringent CO limit of 250 ppmvd at 15 percent O_2 (2.0 g/bhp-hr) is required by SCAQMD Rule 1110.2, effective July 1, 2012 (Reference 1 in Table D-22). Table D-22 contains several source tests demonstrating compliance with this limit.

Sewage Digester Gas
The most stringent CO limit for a sewage digester gas-fired reciprocating IC engine is 250 ppmvd at 15 percent O_2 (2.0 g/bhp-hr). This CO limit is required by SCAQMD Rule 1110.2, effective July 1, 2012 (Reference 1 in Table D-23). Two source tests demonstrating compliance with the CO limit at a wastewater treatment plant are included in Appendix D, Table D-23 (References 5 and 6).

Manure Digester and Co-Digester Gas
The most stringent CO limit for a manure digester or co-digester gas-fired reciprocating IC engine is 210 ppmvd at 15 percent O_2 (1.75 g/bhp-hr). This CO limit is required in the permit for Reference 2 in Table D-24. The next most stringent CO limit of 250 ppmvd at 15 percent O_2 (2.0 g/bhp-hr) is required by SCAQMD Rule 1110.2, effective July 1, 2012 (Reference 1 in Table D-24).

The ARB's 2002 DG BACT Guidance recommended a CO limit of 300 ppmvd at 15 percent O_2 (2.5 g/bhp-hr) as BACT for CO from waste gas-fired reciprocating IC engines (Reference 3 in Table D-22).

The combination of permit limits and source test data in Appendix D for waste gas-fired reciprocating IC engines indicate CO levels of 250 ppmvd (at 15 percent O_2) or less are

[13] Due to the experience at Gallo Cattle Company in Atwater, CA, regulatory agencies should evaluate 9 ppmvd at 15 percent O2 for rich-burn dairy digester gas-fired engines.

achievable. Given that the majority of California is nonattainment for the ozone ambient air quality standards but attainment for the CO ambient air quality standards, ARB staff has identified the most stringent CO limit as 250 ppmvd at 15 percent O_2 from biomethane-fired reciprocating IC engines. Regulatory agencies should evaluate the lower CO limits identified for individual projects that trigger BACT for CO.

iii. Control of VOC Emissions

Landfill Gas

The most stringent VOC limit for an operational landfill gas-fired reciprocating IC engine is 0.1 g/bhp-hr (approximately 20 ppmvd at 15 percent O_2). This VOC limit is required in the permits for Reference 6 in Table D-22, which consist of five identical 4,230 bhp landfill gas-fired engines. Two of the engines failed VOC source tests on two occasions. However, ARB staff found eight source tests at this facility demonstrating compliance with the VOC limit (References 10, 13, 14, 15, 16, 17, 18, and 19 in Table D-22). In addition, source tests at two other facilities demonstrated compliance with 20 ppmvd at 15 percent O_2 (References 5 and 25 in Table D-22).

The next most stringent VOC limit is 28 ppmvd at 15 percent O_2 and is required in the permit for Reference 26 in Table D-22. SCAQMD Rule 1110.2 requires 30 ppmvd at 15 percent O_2, for landfill gas-fired reciprocating IC engines effective July 1, 2012 (Reference 1 in Table D-22). The ARB's 2002 DG BACT Guidance recommended a VOC limit of 130 ppmvd at 15 percent O_2 (0.6 g/bhp-hr) as BACT for VOC from waste gas-fired reciprocating IC engines (Reference 3 in Table D-22).

Sewage Digester Gas

The most stringent VOC limit for a sewage digester gas-fired reciprocating IC engine is 28 ppmvd at 15 percent O_2 (approximately 0.13 g/bhp-hr). This VOC limit is required in the permit for Reference 3 in Table D-23 for a 396 bhp sewage digester gas-fired engine. ARB staff found three source tests demonstrating compliance with the VOC limit (References 5, 6, and 8 in Table D-23).

SCAQMD Rule 1110.2 requires 30 ppmvd at 15 percent O_2, for digester gas-fired reciprocating IC engines effective July 1, 2012 (Reference 1 in Table D-23). The ARB's 2002 DG BACT Guidance recommended a VOC limit of 130 ppmvd at 15 percent O_2 (0.6 g/bhp-hr) as BACT for VOC from waste gas-fired reciprocating IC engines (Reference 2 in Table D-23).

Manure Digester and Co-Digester Gas

The most stringent VOC limit for a co-digester gas-fired reciprocating IC engine (dairy manure and cheese waste) is 20 ppmvd at 15 percent O_2. This VOC limit is required in the permit for Reference 7 in Table D-24. A recent source test confirmed compliance with this limit (Reference 8 in Table D-24).

The most stringent VOC limit for a dairy manure digester gas-fired reciprocating IC engine is 0.13 g/bhp-hr (approximately 28 ppmvd at 15 percent O_2). This VOC limit is required in the permit for Reference 2 in Table D-24.

The next most stringent VOC limit of 30 ppmvd at 15 percent O_2 is required by SCAQMD Rule 1110.2, effective July 1, 2012 (Reference 1 in Table D-24), for digester gas-fired reciprocating IC engines. The ARB's 2002 DG BACT Guidance recommended a VOC limit of 130 ppmvd at 15 percent O_2 (0.6 g/bhp-hr) as BACT for VOC from waste gas-fired reciprocating IC engines (Reference 3 in Table D-24).

The combination of permit limits and source test data for waste gas-fired reciprocating IC engines indicate VOC levels of 20 ppmvd (at 15 percent O_2) or less are achievable. Therefore, ARB staff has identified the most stringent VOC limit as 20 ppmvd at 15 percent O_2 for biomethane-fired reciprocating IC engines.

iv. Control of PM10 Emissions

The PM10 data that ARB staff was able to gather for landfill and digester gas-fired reciprocating IC engines for this Report was very limited. Staff did not locate a BACT determination for PM10 from landfill or digester gas-fired reciprocating IC engines. PM10 permit limits ranged from 0.036 to 0.1 g/bhp-hr (see Tables D-22, D-23, and D-24). Available source tests indicate compliance with 0.1 g/bhp-hr but were in excess of 0.036 g/bhp-hr. Therefore, ARB staff has identified the most stringent PM10 limit as 0.1 g/bhp-hr or less from biomethane-fired reciprocating IC engines.

v. Control of SO_x Emissions

The data set available for this Report to establish a SO_x limit for landfill and digester gas reciprocating IC engines was fairly limited and variable. As expected, SO_x emission limits were tied to fuel sulfur content. Some permits specified use of control systems for removal of H_2S from the waste gas in conjunction with maximum fuel sulfur content limits. Therefore, ARB staff has identified the most stringent SO_x limit as the emission level corresponding to use of a fuel gas pretreatment system for sulfur removal and a maximum fuel sulfur content limit for biomethane-fired reciprocating IC engines.

b. Turbines

This section is not intended to apply to limited use turbines (e.g., operating hours limited to less than 877 hours per year, and in some cases, less than 200 hours per year). District rules and BACT clearinghouses should be consulted for guidance on alternative emission limits allowed for limited use turbines. Some information is included in Appendix D.

i. Control of NO_x Emissions

For the data set collected by ARB staff for this Report, the most stringent permitted NO_x limit for landfill or digester gas-fired turbines is 25 ppmvd at 15 percent O_2. This limit was recommended as BACT in ARB's 2002 DG BACT Guidance (Reference 5 in

Table D-26), and is also referenced as BACT in the SCAQMD and BAAQMD clearinghouses (References 4 and 11 in Table D-26). This NO_x limit is required in the permits for References 6 and 7 in Table D-26. This limit is based on turbines fueled by sewage digester or landfill gas and utilize one or more control methods for NO_x including water or steam injection and low-NO_x combustors.

The most stringent district rule requirement for new and existing gaseous-fueled turbines is contained in SJVAPCD Rule 4703 (References 1 and 2 in Table D-26). While compliance dates for some facilities will extend to 2012, NO_x is limited to 5 ppmvd (at 15 percent O_2) for units rated from 3 to 10 MW[14] and 9 ppmvd (at 15 percent O_2) for units rated less than 3 MW. The District's rule does not distinguish between types of gaseous fuel[15], with the expectation that any issues associated with turbine wear and emission control catalyst deactivation from contaminants present in waste gases can be mitigated by appropriate gas pretreatment systems.

In consideration of the SJVAPCD standards, ARB staff has identified the most stringent NO_x limits as 9 ppmvd (at 15 percent O_2) for biomethane-fired turbines rated less than 3 MW and 5 ppmvd (at 15 percent O_2) for biomethane-fired turbines rated at 3 MW and larger.

ii. Control of CO Emissions

The most stringent CO limit for a landfill or digester gas-fired turbine is 60 ppmvd at 15 percent O_2. This limit was required as BACT for CO in the permit for Reference 10 in Table D-26.

The next most stringent CO limit for a landfill or digester gas-fired turbine is 130 ppmvd at 15 percent O_2. This limit is referenced as BACT in the SCAQMD Guidelines for Non-Major Facilities (Reference 11 in Table D-26). This CO limit is also required in the permits for References 6 and 7 in Table D-26. The emission control technology is not specified in the permit information received by ARB staff.

Source test data for landfill gas-fired turbines at two sites resulted in average CO emissions of 30 to 32 ppmvd at 15 percent O_2 (References 8 and 9 in Table D-26). Therefore, ARB staff has identified the most stringent CO limit as 60 ppmvd at 15 percent O_2 for biomethane-fired turbines.

iii. Control of VOC Emissions

ARB staff received a limited data set on achievable VOC emission levels for landfill and digester gas-fired turbines. ARB staff found no specific BACT determinations for VOC from landfill or digester gas turbines. VOC limits from two permits received by ARB staff

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[14] A slightly higher NOx limit is allowed for turbines that are restricted in their operating hours as an enforceable limit in their permit.
[15] Rule 4703 defines gas fuel as any of the following fuels or fuels containing any of the following fuels: natural gas, LPG, propane, digester gas, and landfill gas.

ranged from 3.5 to 20 ppmvd at 15 percent O_2. Two source tests received by ARB staff measured VOC emissions from 2 to 3.5 ppmvd at 15 percent O_2. Based on this information, ARB staff has identified the most stringent VOC limit as 3.5 ppmvd at 15 percent O_2 for biomethane-fired turbines. However, due to uncertainties about consistent emissions performance, ARB staff recommends that regulatory agencies consult with the turbine manufacturer on guaranteed VOC emission levels as well as evaluate additional source test results to assess the appropriate VOC limit for biomethane-fired turbines.

iv. Control of PM10 Emissions

ARB staff received insufficient data on achievable PM10 emission levels for landfill and digester gas-fired turbines to recommend a specific PM10 emission limit at this time. However, SCAQMD and BAAQMD BACT guidelines specify fuel gas pretreatment for particulate removal as BACT for PM10 for landfill and digester gas-fired turbines. Therefore, ARB staff has identified the most stringent PM10 limit as the emission level corresponding to use of a fuel gas pretreatment system for particulate removal for biomethane-fired turbines.

v. Control of SO_x Emissions

Like other fuels, fuel sulfur is the source of SO_x emissions from turbines fired on landfill and digester gas. Since SO_x emissions are highly dependent on fuel sulfur content, the lowest emissions are achieved through the combustion of fuels with the lowest sulfur. However, an applicant has limited control over the incoming waste stream to landfills and wastewater treatment plants. Therefore, ARB staff recommends establishing a SO_x limit based on setting a limit on the maximum sulfur content of the fuel. This is consistent with BAAQMD BACT Guideline 89.3.1 for landfill gas-fired turbines (Reference 4 in Table D-26) and SCAQMD Guidelines for Non-Major Facilities (Reference 11 in Table D-26). Therefore, ARB staff has identified the most stringent SO_x limit as the emission level corresponding to use of landfill gas with a sulfur content of no more than 150 ppmv as H_2S and sewage digester gas with a sulfur content of no more than 40 ppmv as H_2S for biomethane-fired turbines.

T. Other Operations and Equipment

1. Pyrolyzer

ARB staff did not locate any permits for commercially operating pyrolyzers using biomass feedstocks. ARB staff received one permit for an experimental research demonstration pyrolysis unit in the SCAQMD that used sorted municipal solid waste and sewage sludge as feedstock. However, the unit is no longer operating and no longer has a valid air permit. The permit limited the operating hours as well as emissions to just below the levels that would trigger federal requirements for small municipal solid waste combustors. According to District staff, is it likely that more efficient air pollution control would have been required if the company requested either more operating time and/or higher throughput. Therefore, ARB staff does not have sufficient information to identify the most stringent emission levels for a pyrolyzer using biomass feedstocks for transportation fuels at this time. ARB staff will include pyrolyzers in future report updates.

2. Biomass Syngas-Fueled Reciprocating IC Engine

ARB staff did not locate any biorefineries in the State that produce transportation fuels from biomass-derived synthesis gas (i.e., syngas). However, staff did find a gasification system at Parreira Almond Processing Company in Los Banos, California, that converts orchard trimmings into syngas that is used in a generator to produce electricity. The California Integrated Waste Management Board provided a low-interest loan to Ortigalita Power Company to help fund the purchase and installation of the gasification equipment at Parreira Almond. The project received an ATC from the SJVAPCD. Information from the BACT analysis for the project is included for informational purposes, since staff expects that this equipment could be used at a biorefinery in the future.

a. Control of NO_x Emissions

The most stringent NO_x limit for a biomass syngas-fueled reciprocating IC engine is 5 ppmvd at 15 percent O_2. This NO_x limit is listed as technologically feasible BACT in SJVAPCD Guideline 3.3.14 (Reference 2 in Table D-25). The next most stringent NO_x limit is 9 ppmvd at 15 percent O_2. This NO_x limit is listed as achieved-in-practice BACT in SJVAPCD Guideline 3.3.14 (Reference 1 in Table D-25). Therefore, ARB staff has identified the most stringent NO_x limit as 5 ppmvd at 15 percent O_2 for syngas-fueled reciprocating IC engines.

b. Control of VOC Emissions

The most stringent VOC limit for a biomass syngas-fueled reciprocating IC engine is 25 ppmvd at 15 percent O_2. This NO_x limit is listed as achieved-in-practice BACT in SJVAPCD Guideline 3.3.14 (Reference 1 in Table D-25). Therefore, ARB staff has identified the most stringent VOC limit as 25 ppmvd at 15 percent O_2 for syngas-fueled reciprocating IC engines.

3. Composting

While composting operations are not directly related to biofuel production processes, ARB staff anticipates that composting may be conducted at biorefineries to manage waste feedstocks.

a. Control of VOC and NH_3 Emissions

Sample permits received by ARB staff included facilities that conduct composting operations both outside and within the confines of an enclosed building. For processes within an enclosure, the most stringent VOC and ammonia (NH_3) limits require 80 percent control efficiency by weight. This is typically achieved by venting VOC and NH_3 emissions generated within the enclosure (i.e., the building and/or in-vessel compost container) to a biofilter. This is required in SCAQMD Rule 1133.2 and in the permits for References 1, 4, 5, and 6 in Table D-27). Therefore, ARB staff has identified the most stringent VOC limit as the emission level corresponding to the use of a control system (enclosure with biofilter or equivalent technology) capable of 80 percent or better control efficiency, and a NH_3 limit corresponding to the use of a control system capable of 80 percent or better control efficiency.

b. Control of PM10 Emissions

Permits for composting facilities require the use of water trucks, sprays, or sprinklers to limit PM10 emissions generated from transfer points, stockpiles, and handling operations. The most stringent PM10 mitigation technique is a dust collection system consisting of a cartridge filter baghouse located within a building in the screening area (see Reference 4 in Table D-27). Typical PM10 control efficiency for a baghouse is 99 percent or more. Therefore, ARB staff has identified the most stringent PM10 limit as the emission level corresponding to the use of a PM10 control system (enclosure with baghouse or equivalent technology) capable of 99 percent or better control efficiency.

4. Diesel-Fueled Emergency Engine Generator

Diesel-fueled engine generator sets are used by almost all types of businesses for emergency power supply if the power grid fails and can be expected to be included at biorefineries.

a. Control of NO_x, CO, VOC, and PM10 Emissions

The most stringent NO_x, CO, VOC, and PM10 limits for a diesel-fueled emergency engine generator are the emission limits corresponding to the latest U.S. EPA Tier certification levels for off-road compression ignition engines for the applicable bhp range. These emission limits are required statewide via the ARB's ATCM for Stationary Compression Ignition Engines, which was adopted by the Board in 2003 and last amended in 2006 (References 2 and 3 in Table D-28). The off-road engine standards are listed in Table D-29. Several districts have adopted the ATCM requirements into their own rule books and/or included them in their BACT clearinghouses (References 1, 4, and 5 in Table D-28). Therefore, ARB staff has identified the most stringent NO_x, CO, VOC, and PM10 limits as the emission limits corresponding to the latest U.S. EPA Tier certification levels for off-road compression ignition engines for the applicable bhp range.

b. Control of SO_x Emissions

The most stringent SO_x limit for a diesel-fueled emergency engine generator is an emission limit corresponding to use of CARB, or very low sulfur, diesel (15 ppmw sulfur or less). Use of CARB diesel is required by the statewide ATCM for Stationary Compression Ignition Engines (References 2 and 3 in Table D-28). CARB diesel is also listed as meeting BACT for SO_x for diesel-fueled emergency IC engines in the SJVAPCD, SCAQMD, and BAAQMD (References 1, 4, and 5 in Table D-28). Therefore, ARB staff has identified the most stringent SO_x limit as the emission level corresponding to use of CARB, or very low sulfur, diesel for diesel-fueled emergency engine generators.

U. GHG Emission Reduction Measures

GHGs are being evaluated in other existing ARB activities associated with AB 32. AB 32 directs California to reduce its GHG emissions to 1990 levels by 2020. ARB is designated as the lead agency for implementation, and is working with the California Environmental Protection Agency to coordinate the statewide effort to achieve real, quantifiable, and cost-effective reductions in GHG emissions.

AB 32 requires ARB to adopt a Scoping Plan (Plan) that outlines how GHG emission reductions will be achieved to meet the 2020 limit. Following adoption of the Plan, activities will be developed to achieve the maximum technologically feasible and cost-effective reductions in GHG emissions. Activities may include direct regulations, alternative compliance mechanisms, monetary and non-monetary incentives, voluntary actions, and market-based mechanisms such as a cap-and-trade system. These activities are being considered for the following sectors: agriculture, electricity, forestry, high global warming potential, land use and local initiatives, manufacturing, and waste management/recycling. AB 32 also requires that the ARB develop GHG reduction strategies that do not interfere with efforts to achieve and maintain federal and state ambient air quality standards and to reduce TAC emissions.

The mitigation strategies recommended in this Report will not only provide further reductions in the pollutants addressed in this Report, but also reduce GHGs. These strategies achieve GHG reductions by promoting overall efficiency in energy conversion technologies and encouraging the recovery of energy and other marketable products from biomass feedstocks. Implementation of the mitigation strategies will allow users of electricity, heat, and liquid and gaseous fuels to partially offset their reliance upon fossil fuels, reduce GHGs, and preserve efforts to achieve and maintain federal and state ambient air quality standards and to reduce TAC emissions. ARB staff expects that the mitigation strategies recommended in this Report will serve as a starting place for considering strategies and measures to reduce GHGs from biomass facilities.

VI.

MOST STRINGENT EMISSION LIMITS IDENTIFIED FOR PROCESS EQUIPMENT AT BIOREFINERIES

Table VI-1 summarizes the most current stringent emission limits identified by ARB staff for process equipment that might be used at biorefineries. The alternate limits listed under certain equipment categories in Table VI-1 were identified by ARB staff as being the most stringent emission limit for an individual air pollutant contained in a rule or regulation, guidance document, BACT analysis, or permit. In the case of biomethane-fueled fuel cells, the alternate limits are the future emission standards that will be required by statewide regulation as of January 1, 2013. Data collected by ARB staff indicates the 2013 standards may be achievable now, and therefore, ARB staff recommends that regulatory agencies evaluate the feasibility of the alternate limit for an individual project. For the other equipment categories, ARB staff did not have sufficient data at the drafting of this Report to determine that the alternate limit is achievable in conjunction with the other corresponding most stringent emission limits identified for the class/category of source. In these cases, ARB staff also recommends that regulatory agencies evaluate the feasibility of the alternate limit for an individual project.

Table VI-1. Most Stringent Emission Limits Identified for Process Equipment at Biorefineries

Class/Category of Source	NO_x	CO	VOC	SO_x	PM10
Grain receiving, conveying, and grinding operations					Emission limit corresponding to use of a baghouse with 99% control, or equivalent
Methanol / Sodium Methoxide receiving and storage			Emission limit corresponding to use of a VOC control system capable of 99.5% or better control efficiency		
Fermentation process: yeast, liquefaction, beerwell, and process condensate tanks			Emission limit corresponding to use of a VOC control system capable of 99.5% or better control efficiency		
Distillation and wet cake processes			Emission limit corresponding to use of a VOC control system (wet scrubber or equivalent)		

Class/Category of Source	NO_x	CO	VOC	SO_x	PM10
			capable of 95% or better control efficiency		
Natural gas-fired boiler, ≥2 to <5 MMBtu/hr	Non-atmospheric units: 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu) Atmospheric units: 12 ppmvd @ 3% O_2 (0.015 lb/MMBtu)	Firetube type: 50 ppmvd @ 3% O_2 Watertube type: 100 ppmvd @ 3% O_2	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf
Natural gas-fired boiler, ≥5 to <20 MMBtu/hr	6 ppmvd @ 3% O_2 (0.007 lb/MMBtu)	Firetube type: ≤50 ppmvd @ 3% O_2 Watertube type: ≤100 ppmvd @ 3% O_2	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf
Natural gas-fired boiler, ≥20 MMBtu/hr	5 ppmvd @ 3% O_2 (0.0062 lb/MMBtu)	Firetube type: ≤50 ppmvd @ 3% O_2 Watertube type: ≤100 ppmvd @ 3% O_2 For units ≥250 MMBtu/hr[16]: 10 ppmvd @ 3% O_2	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf	Emission limit corresponding to use of natural gas with fuel sulfur content of no more than 1 gr/100 scf
Pumps and compressor seals			No leak of methane greater than 100 ppm above background and inspection and maintenance program		
Valves, flanges, and other types of connectors			No leak of methane greater than 100 ppm above background and inspection and maintenance program		
Wet cooling tower					Emission limit corresponding to use of a drift

[16] This CO limit may be required for boilers rated at <250 MMBtu/hr if an oxidation catalyst is found to be cost effective, is necessary to meet toxic best available control technology, or for VOC emission control.

Class/Category of Source	NO_x	CO	VOC	SO_x	PM10
					eliminator with 0.0005% drift loss
Natural gas-fired dryer	0.018 lb/MMBtu (15 ppmv @ 3% O_2)	0.07 lb/MMBtu	Emission limit corresponding to use of a VOC capture and control with thermal or catalytic incineration (98% control) or equivalent	Emission limit corresponding to use of a wet scrubber (95% control)	Emission limit corresponding to use of high efficiency (1D-3D) cyclones and thermal incinerator in series (98.5% control) or equivalent
Storage tank (fixed roof)			Emission limit corresponding to use of a VOC control system capable of 99.5% or better control efficiency		
Storage tank (floating roof)			Emission limit corresponding to use of a VOC control system capable of 98% or better control efficiency		
Flare (ethanol production)	0.05 lb/MMBtu	0.37 lb/MMBtu	0.063 lb/MMBtu	0.00285 lb/MMBtu	0.008 lb/MMBtu
Liquid fuel loading operations			Emission limit corresponding to use of a VOC control system capable of 98% or better control efficiency		
Liquid fuel transfer and dispensing operations			Emission limit corresponding to use of an ARB certified Phase I vapor recovery system		
Biomass-fired boiler	0.012 lb/MMBtu (*9 ppmvd @ 3% O_2*)	0.046 lb/MMBtu (*59 ppmvd @ 3% O_2*) Alternate Limit: 0.01 lb/MMBtu (*22 ppmvd @ 3% O_2*)	0.005 lb/MMBtu (*11 ppmvd @ 3% O_2*)	0.012 lb/MMBtu (*7 ppmvd @ 3% O_2*)	0.024 lb/MMBtu (*0.01 gr/scf @ 12% CO_2*)
Landfill gas-fired flare	0.025 lb/MMBtu	0.06 lb/MMBtu	Emission limit corresponding to 98% VOC	Emission limit corresponding to use of a wet	Emission limit corresponding to use of steam

Class/Category of Source	NO_x	CO	VOC	SO_x	PM10
			destruction efficiency or 20 ppmv @ 3% O_2	scrubber with 98% control efficiency	injection and/or knockout vessel
Manure digester and co-digester gas-fired flare	0.03 lb/MMBtu (*25 ppmvd @ 3% O_2*)	Operate per manufacturer specifications to minimize CO	0.03 lb/MMBtu	Emission limit corresponding to use of a H_2S removal system (dry or wet scrubber or equivalent)	Emission limit corresponding to use of smokeless combustion and LPG or natural gas-fired pilot
Compressed gas dispensing operations	No emissions – use of closed loop system with all vent and excess process gas directed to an on site treatment system, used in vehicles, or directed to another combustion or processing facility that can process the biogas and which has been issued a valid air permit				
Biomethane-fueled fuel cell[17]	0.5 lb/MWh Alternate Limit: 0.07 lb/MWh	6.0 lb/MWh Alternate Limit: 0.10 lb/MWh	1.0 lb/MWh Alternate Limit: 0.02 lb/MWh	N/A	N/A
Biomethane-fired microturbine	0.5 lb/MWh As of 1/1/2013: 0.07 lb/MWh	6.0 lb/MWh As of 1/1/2013: 0.10 lb/MWh	1.0 lb/MWh As of 1/1/2013: 0.02 lb/MWh	N/A	N/A
Biomethane-fired reciprocating internal combustion engine	11 ppmvd @ 15% O_2 (or 0.15 g/bhp-hr) in conjunction with an effective and efficient biogas treatment system Alternate Limit for dairy digester gas-fired rich-burn engines: 9 ppmvd @ 15% O_2 (or 0.15 g/bhp-hr)	250 ppmvd @ 15% O_2	20 ppmvd @ 15% O_2	Emission limit corresponding to use of a fuel gas pretreatment system for sulfur removal along with maximum fuel sulfur content limit	0.1 g/bhp-hr
Biomethane-fired turbine, <3 MW	9 ppmvd @ 15% O_2	60 ppmvd @ 15% O_2	3.5 ppmvd @ 15% O_2 [18]	Landfill gas: Emission limit corresponding to use of landfill gas with sulfur content of no more than 150 ppmv as	Emission limit corresponding to use of a fuel gas pretreatment system for particulate removal

[17] Emission limits are the 2008 standards for waste gas required by the ARB's Distribution Generation (DG) Certification Regulation. Alternate limits represent the 2013 standards for waste gas required by the DG Certification Regulation.
[18] Due to limited data set available for this Report on achievable VOC emission levels for landfill and digester gas-fired turbines, ARB staff recommends that regulatory agencies consult with the

Class/Category of Source	NO_x	CO	VOC	SO_x	PM10
Biomethane-fired turbine, ≥3 MW	5 ppmvd @ 15% O_2			H_2S Digester gas: Emission limit corresponding to use of digester gas with sulfur content of no more than 40 ppmv as H_2S	
Biomass syngas-fueled reciprocating internal combustion engine	5 ppmvd @ 15% O_2	N/A	25 ppmvd @ 15% O_2	N/A	N/A
Composting			Emission limit corresponding to use of a VOC control system (enclosure with biofilter or equivalent) capable of 80% or better control efficiency Ammonia: Emission limit corresponding to use of an NH3 control system capable of 80% or better control efficiency		Emission limit corresponding to use of a PM10 control system capable of 99% or better control efficiency
Diesel-fueled emergency engine generator	Cleanest available U.S. EPA Tier certification level for applicable horsepower range[19]	Cleanest available U.S. EPA Tier certification level for applicable horsepower range	Cleanest available U.S. EPA Tier certification level for applicable horsepower range	Emission limit corresponding to use of CARB, or very low sulfur, diesel fuel (15 ppm sulfur by weight)	Cleanest available U.S. EPA Tier certification level for applicable horsepower range

manufacturers on guaranteed emission levels, as well as, evaluate additional source tests to determine the appropriate VOC limit for a turbine.

[19] Refer to U.S. EPA regulations and/or Appendix D Table D-29 of this Report for the applicable emission standard.

VII.

REGULATION OF MOBILE SOURCE EMISSIONS

"Mobile sources" include a variety of vehicles, engines, and equipment. On-road sources include vehicles used on roads for transportation of passengers, goods, and materials. Off-road sources include vehicles, engines, and equipment used for construction, mining, recreation, recycling, and airport ground support. This section describes ARB's in-use diesel-fueled mobile source regulations that apply to vehicles and equipment that may be associated with new or expanding biorefineries. ARB staff is currently evaluating the regulations to identify provisions that may require modification. Therefore, the websites provided in this chapter should be consulted to determine the most current requirements of these regulations.

Portable engines and equipment that are exempt from ARB regulations may be subject to district permitting requirements. District permit requirements will vary, depending on the attainment status in the district. Some districts have implemented registration programs specifically for portable engines and equipment units. Owners of portable engines in these districts can register engines with the district by demonstrating that the engines meet specific emission rates. Some districts specifically exempt portable engines from permit requirements or have specific requirements for individual types of portable engines and/or equipment.

A. On-Road Vehicles

1. On-Road Heavy-Duty Vehicle In-Use Regulation

ARB's On-Road Heavy-Duty Vehicle In-Use Regulation requires existing on-road diesel vehicles operating in California to meet performance requirements between 2011 and 2023. The regulation applies to all on-road heavy-duty diesel fueled vehicles with a gross vehicle weight rating (GVWR) greater than 14,000 pounds, agricultural yard trucks with off-road certified engines, and certain diesel fueled shuttle vehicles of any GVWR. Out-of-state trucks and buses that operate in California are also subject to the regulation. Fleets with one to three vehicles are exempt from the regulation until January 2014. For more information on the On-Road Heavy-Duty Vehicle In-Use Regulation, go to: http://www.arb.ca.gov/msprog/onrdiesel/onrdiesel.htm.

2. Diesel PM Control Measure for On-Road Heavy-Duty Diesel-Fueled Residential and Commercial Solid Waste Collection Vehicle (SWCV)

ARB's SWCV Regulation requires that fleets install BACT to reduce diesel PM, with a phased in compliance schedule that began in 2004 and ends in 2010. The regulation applies to owners of SWCVs or those diesel-fueled trucks over 14,000 pounds GVWR with 1960 through 2006 model year engines used to collect residential and commercial solid waste. For more information on the SWVC Regulation, go to: http://www.arb.ca.gov/msprog/SWCV/SWCV.htm.

3. Diesel PM Control Measure for On-Road Heavy-Duty Diesel-Fueled Vehicles Owned or Operated By Public Agencies and Utilities

ARB's Fleet Rule for Public Agencies and Utilities requires that fleets reduce diesel PM with a phased in compliance schedule that began in 2006 and ends in 2011. The schedule is based on engine model year and county population for which the vehicle and the agency reside. The regulation applies to any municipality or utility that owns, leases, or operates an on-road diesel-fueled heavy-duty vehicle with a manufacturer's GVWR greater than 14,000 pounds powered by a 1960 through 2006 model year medium heavy-duty or heavy heavy-duty engine. The regulation does not provide an exemption based on the size of a fleet. For more information on the Fleet Rule for Public Agencies and Utilities, go to: http://www.arb.ca.gov/msprog/publicfleets/publicfleets.htm.

B. Off-Road Vehicles

1. In-Use Off-Road Diesel Vehicle Regulation

ARB's Off-Road Regulation requires vehicles to apply exhaust retrofits and accelerate turnover of fleets to newer, cleaner engines. The regulation applies to self-propelled diesel-fueled vehicles with engines 25 horsepower (hp) and greater that cannot be registered and licensed to drive on-road. These vehicles are used in construction, mining, recycling, airport ground support and other industries. The Off-Road Regulation establishes annual fleet average emission targets for PM and NO_x that become more stringent over time. If in any year that a fleet does not meet the fleet average targets, the fleet must turnover and retrofit a maximum percentage of their total horsepower. The initial compliance dates are earliest for large fleets with a total maximum power greater than 5,000 hp (2010), followed by medium fleets (2013), and then small fleets with total maximum power of less than or equal to 2,500 hp (2015). The small fleets are exempt from the NO_x fleet average portion of the regulation. For more information on the In-Use Off-Road Diesel Vehicle Regulation, go to: http://www.arb.ca.gov/msprog/ordiesel/ordiesel.htm.

2. Fleet Requirements for Large Spark Ignition (LSI) Engine Forklifts and Other Industrial Equipment

ARB's LSI Fleet Regulation establishes fleet average emission level requirements for hydrocarbons (HC) and NO_x that began in 2009 and become more stringent with time. The regulation applies to owners and operators of LSI engines 25 hp or greater used in forklifts, sweepers/scrubbers, industrial tugs (tow tractors), and airport ground support equipment. Small fleets with one to three pieces of equipment are exempt from the fleet averages. For more information on the LSI Fleet Regulation, go to: http://www.arb.ca.gov/msprog/offroad/orspark/orspark.htm.

C. Portable Engines and Equipment

1. Portable Diesel Engine Air Toxic Control Measure

ARB's Portable Diesel Engine ATCM requires all diesel-fueled portable engines 50 hp and greater to meet progressively more stringent fleet-averaged PM emission standards over time. For more information on the Portable Diesel Engine ATCM, go to: http://www.arb.ca.gov/diesel/peatcm/peatcm.htm.

VIII.

MOBILE SOURCE EMISSIONS ASSOCIATED WITH BIOREFINERIES

This chapter provides an overview of the mobile source emissions associated with new or expanding biorefineries. On-road vehicles, off-road vehicles, and portable equipment used at biorefineries are a source of criteria pollutants, TACs, and GHGs. These mobile sources may be used for the following activities associated with biorefineries:

- construction and maintenance;
- delivery of raw product;
- processing of raw material and finished fuel product; and
- delivery of finished fuel product.

A. On-Road Vehicles

On-road diesel vehicles are a source of CO, diesel PM, HC, and NO_x emissions. This category of mobile sources includes light-duty vehicles, light-duty trucks, and heavy-duty vehicles used for on-road transportation. The following is a partial listing of the types of on-road vehicles that may be used for the delivery and processing of raw material and finished fuel product at biorefineries:

- solid waste collection vehicles,
- dump trucks,
- feedstock/ raw product delivery trucks, and
- fuel delivery trucks.

B. Off-Road Vehicles

Off-road diesel vehicles are a source of CO, diesel PM, HC, and NO_x emissions. Off-road vehicles may be used during the various stages of construction and maintenance of biorefineries including demolition, clearing, dewatering, excavation, grading, paving, surfacing, foundation work, building erection and other infrastructure developments. The following is a partial listing of the types of off-road vehicles that may be used for the construction and maintenance of biorefineries:

- loaders,
- excavators,
- dozers,
- drill rigs, and
- forklifts.

C. Portable Engines and Equipment

Portable engines and equipment are a source of CO, diesel PM, HC, NO_x, and fugitive emissions of PM. Portable engines are used for a variety of applications, including pumps, cranes, oil well drilling, power generators, dredging equipment, rock crushing and screening equipment, welding equipment, wood chippers, and compressors. The following is a partial listing of the types of portable equipment that may be used for the construction and maintenance; and processing of raw material at biorefineries:

- compressors,
- generators,
- pumps,
- cranes,
- pile drivers,
- welders, and
- chippers and grinders.

IX.

MITIGATION OF MOBILE SOURCE EMISSIONS ASSOCIATED WITH BIOREFINERIES

Mobile source emissions associated with biorefineries may be mitigated by obtaining emission reductions beyond those required by ARB's in-use diesel-fueled mobile source regulations, and the use of other mitigation strategies. This chapter provides an overview of the options available to obtain surplus emission reductions and other strategies to mitigate air emissions from mobile sources associated with biorefineries.

A. Exceeding the Requirements of In-Use Diesel-Fueled Mobile Source Regulations

ARB's in-use diesel-fueled mobile source regulations reduce criteria pollutant, diesel PM, other TAC, and GHG emissions from mobile sources. Mitigation of mobile source emissions associated with biorefineries may be achieved through emission reductions that go beyond what is required by ARB's regulations. This may include early compliance, emission reductions from exempt fleets, or reductions greater than what is required. These reductions may be attained by:

1. Repower

Engine repower means the replacement of an existing engine with a new, cleaner certified engine instead of rebuilding the existing engine to its original specifications.

2. Retrofit

Retrofit means the installation of a verified emission control system on an existing engine. Examples include, but are not limited to, diesel particulate filters and catalyst systems.

3. New Purchases

New purchases refer to non-fleet modernization purchases of vehicles or equipment certified to optional, lower emission standards.

4. Fleet Modernization

Fleet modernization refers to the replacement of an older truck or piece of equipment that still has remaining useful life with a newer, cleaner truck or piece of equipment. The old vehicle/equipment is scrapped.

5. Alternative Fuel Use

Alternative fuel use means the use of fuels that have lower emissions than standard gasoline or diesel.

B. Other Strategies to Mitigate Air Emissions from Mobile Sources Associated with Biorefineries

Table IX-1 provides other strategies to further mitigate air emissions from mobile sources associated with biorefineries. These include strategies to reduce diesel PM emissions, fugitive PM emissions, vehicle miles travelled (VMT), single occupancy vehicles (SOV), and exposure to sensitive receptors.

ARB's 2005 Air Quality and Land Use Handbook (Handbook) was the source of some of the mitigation options found in Table IX-1. The Handbook was developed to promote enhanced communication among land use agencies, local air pollution control agencies, and sensitive receptors.

The Handbook summarizes the air quality issues associated with emissions from industrial, commercial, and mobile sources of air pollution and provides recommendations to ensure that appropriate distances are maintained between sources of air pollution and sensitive receptors.

ARB staff also reviewed the following documents to provide the list of potential strategies to mitigate mobile source emissions associated with biorefineries:

- California Air Pollution Control Officers Association's Health Risk Assessment for Proposed Land Use Projects (2009);
- Business, Transportation, and Housing and the California Environmental Protection Agency's Goods Movement Action Plan (2007);
- California Department of Public Health's A Guide for Health Impact Assessment (2009);
- State and local CEQA guidelines; and
- Draft and final EIRs for various industrial facilities.

In addition, ARB staff recently released a report entitled, Proposed Screening Method for Low-Income Communities Highly Impacted by Air Pollution for AB 32 Assessments. This report provides a method to identify low-income communities that are highly impacted by air pollution for the purposes of meeting the requirements of AB 32, specified in Health and Safety Code Section 38570(b)(1). This report can also be used to determine the location of low-income communities that are highly impacted by air pollution when considering the site selection and proximity to sensitive receptors for new or expanding biorefineries. For current information on activities related to this report, go to ARB's Climate Action Team Public Health Workgroup website at: http://www.arb.ca.gov/cc/ab32publichealth/ab32publichealth.htm.

Table IX-1. Other Strategies to Mitigate Air Emissions from Mobile Sources Associated with Biorefineries

	Mitigation Strategy	Description
1.	Reduce Diesel PM Emissions	• Encourage the use of low emission locomotives for the rail transport of raw material and finished fuel product. • Reduce emissions from idling locomotives used to transport raw material and finished fuel product. • Reduce emissions from idling vehicles by improving traffic flow by signal synchronization, or improved road infrastructure. • Use "clean" street sweepers. • Maintain diesel engines and retrofit air pollution control device according to manufacturer's specifications
2.	Reduce Fugitive PM Emissions	• Cover, wet all material, or maintain at least two feet of vertical space between the top of the load and the top of the trailer for all trucks hauling, dirt, sand, soil or other loose materials. • Wash off trucks and any equipment exiting unpaved roads onto paved roads using wheel washers, trackout devices, etc. • Limit or remove mud or dirt from adjacent public streets at the end of each workday. • Consider watering roads on days of moderate to high traffic to improve moisture and control PM. • Consider dust suppressants to control PM, • Cover, wet to limit visible dust emissions, and maintain at least six inches of freeboard space from the top of the container when materials are transported off-site. • Pave access roads at least 100 feet onto the site from main road. • Sweep streets once a day if visible soil materials are carried to adjacent streets (recommend water sweepers with reclaimed water). • Apply water three times daily, or non-toxic dust suppressant to all unpaved parking or staging areas or unpaved road surfaces. • Reduce traffic speeds on all unpaved roads to 15 miles per hour or less.
3.	Reduce Product (Raw and Finished) VMT	• Provide incentives for on-site fueling to minimize fuel export traffic.
4.	Reduce Passenger VMT and SOVs	• Design and locate buildings to facilitate transit access (e.g., locate building entrances near transit stops, eliminate building setbacks). • Establish new cooperative relationships among employers and employees to reduce VMT. • Work with large employers and commercial/industrial complexes to create Transportation Management Associations and to implement trip/VMT reduction

	Mitigation Strategy	Description
	Reduce Passenger VMT and SOVs (cont.)	strategies. • Cooperate with surrounding jurisdictions to provide incentives, adopt regulations and develop transportation demand management programs that reduce vehicle trips and VMT. • Develop programs and educate employers about employee rideshare and transit • Establish mass transit mechanisms for the reduction of work related and non-work related vehicle trips • Promote mass transit ridership through careful planning of routes. • Provide electrical charging station for electric vehicles. • Identify and develop non-motorized transportation corridors (e.g., bicycling & walking trails). • Provide incentives for car-pool, van-pool, or zero emissions vehicles to discourage single occupancy commuters. • Provide on-site eating, refrigeration and food vending facilities to reduce lunchtime SOV trips. • Implement compressed work schedules (i.e., 9–80s or 4–10s). • Implement a telecommuting program. • Implement a lunchtime shuttle to reduce single occupant vehicle trips. • Construct satellite worksites.
5.	Reduce Exposure to Sensitive Receptors	• Consider co-located operations that consolidate truck traffic. • Develop routes for truck traffic that discourage use of roads in sensitive receptor neighborhoods. • Reduce vehicle miles traveled through adjacent residential property.

X.

FUTURE CONSIDERATIONS

ARB staff will establish a website to post future BACT determinations, source test results, new technologies, newly approved regulations (including test methods), and a current list of existing biorefineries in California. When this information is posted to the website, ARB staff will send e-mail notifications to the LCFS listserve at ARB, and the Bioenergy listserve at CEC.

ARB staff found that the source test methods used to verify compliance with permitted PM10 emission limits for biomass-fired boilers were not necessarily comparable. For PM testing, some facilities used EPA Method 5 in conjunction with EPA Method 202, while other facilities used EPA Method 201A in conjunction with EPA Method 202. EPA Method 201A is an in-stack PM10 measurement method and EPA Method 202 is a condensable PM measurement method used in conjunction with EPA Method 201 or 201A. However, EPA Method 5 is designated as a mass PM measurement method. One permit reviewed by ARB staff specifically stated that if EPA Method 5 is used, then it shall be assumed that 100 percent of PM is PM10.

For future updates concerning particulate emissions from biomass-fired boilers, ARB staff plans to identify the source test methods required to show compliance with the PM10 permit limits. ARB staff also plans to incorporate anticipated upcoming PM2.5 permit limits and corresponding source test method recommendations in future updates. ARB staff will also address any newly-adopted regulations for biorefineries.

Over time, it is expected that new biorefineries and conversion technologies will be developed in California. To ensure the information provided in this Report stays current, ARB staff will perform periodic updates at intervals that correspond to the review periods set forth in the LCFS regulation, but not more frequent than every five years. As part of these updates, staff will assess the geographic distribution of biorefineries in the state, and where appropriate, integrate additional mitigation measures for the purpose of protecting against air quality impacts that arise from the concentration or co-location of multiple biorefineries.

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APPENDIX A

State of California
AIR RESOURCES BOARD

Resolution 09-31

April 23, 2009

Agenda Item No.: 09-4-4

WHEREAS, sections 39600 and 39601 of the Health and Safety Code authorize the Air Resources Board (ARB or the Board) to adopt standards, rules and regulations and to do such acts as may be necessary for the proper execution of the powers and duties granted to and imposed upon the Board by law;

WHEREAS, the California Global Warming Solutions Act of 2006 (AB 32; Stats 2006, ch. 488, Health and Safety Code sections 38500-38599) declares that global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California, and creates a comprehensive multi-year program to reduce California's greenhouse gas (GHG) emissions to 1990 levels by 2020;

WHEREAS, section 38510 of the Health and Safety Code designates ARB as the State agency charged with monitoring and regulating sources of GHG emissions that cause global warming in order to reduce such emissions;

WHEREAS, section 38560 of the Health and Safety Code directs the Board to adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective GHG emission reductions from sources or categories of sources, subject to the criteria and schedules specified in Part 4 of Division 25.5 of the Health and Safety Code;

WHEREAS, section 38560.5 of the Health and Safety Code requires the Board to publish and make available to the public a list of discrete early action GHG reduction measures (Discrete Early Action Measures) on or before June 30, 2007, and directs the Board to adopt regulations on or before January 1, 2010 to implement the Discrete Early Action Measures; these regulations are to be enforceable no later than January 1, 2010;

WHEREAS, section 38560.5(c) of the Health and Safety Code provides that the regulations adopted to implement Discrete Early Action Measures must achieve the maximum technologically feasible and cost-effective reductions in GHG emissions;

WHEREAS, in January 2007, Governor Schwarzenegger issued Executive Order S-01-07, which established the goal of developing a low carbon fuel standard (LCFS) to reduce the carbon intensity of transportation fuels by at least 10 percent by 2020; the Executive Order provides that the LCFS shall apply to all providers of transportation fuels in- California, be measured on a full fuels cycle basis, and authorize compliance through market-based methods;

WHEREAS, Executive Order S-01-07 directed ARB to determine if the LCFS could be adopted as a Discrete Early Action Measure and, if so, to consider adoption of the LCFS on the list of Discrete Early Action Measures required to be identified by June 30, 2007 pursuant to Health and Safety Code section 38560.5;

WHEREAS, the Board approved a list of early GHG actions at its June 21, 2007 hearing and approved additions to the list at its October 25, 2007 hearing, and a subset of nine of these early actions were designated as Discrete Early Action Measures including the "Low Carbon Fuel Standard" measure to reduce GHG emissions from transportation fuels used in California;

WHEREAS, after a public meeting on December 11, 2008, the Board approved the Climate Action Scoping Plan, which includes the LCFS Discrete Early Action Measure;

WHEREAS, section 57004 of the Health and Safety Code requires an external peer review of the scientific portions of ARB regulations establishing a regulatory level, standard, or other requirement for the protection of public health or the environment;

WHEREAS, Health and Safety Code section 43830.8(a) prohibits the Board from adopting a regulation that establishes a specification for a motor vehicle fuel unless a multimedia evaluation for the regulation undergoes the review process specified in the statute; however, this multimedia requirement does not apply if the regulation does not establish a motor-vehicle fuel specification;

WHEREAS, Congress adopted a renewable fuels standard (RFS) in 2005 and strengthened it (RFS2) in December 2007 as part of the Energy Independence and Security Act of 2007 (EISA); the RFS2 requires that 36 billion gallons of biofuels be sold annually in the United States by 2022, of which 21 billion gallons must be "advanced" lower carbon biofuels and the other 15 billion gallons can be corn ethanol;

WHEREAS, the staff has proposed a new regulation establishing an LCFS for California; the proposed regulation is set forth in Attachment A hereto and includes the following elements:

> Identify "carbon intensity" as a measure - expressed in terms of grams of CO2 equivalent per mega-Joule (grams CO2E/MJ) - of the direct and indirect GHG emissions associated with each of the steps in the full fuel cycle of a transportation fuel (also referred to as "well-to-wheels" for fossil fuels, or "seed or field-to-wheels" for biofuels);

Establish an LCFS that achieves a 10 percent reduction in average carbon intensity by starting specified providers of transportation fuels (referred to as "regulated parties") at an initial level for 2011 and incrementally lowering the allowable carbon intensity for transportation fuels used in California in each subsequent year through 2020; the overall carbon intensity of the pool of transportation fuels for which. each regulated party is responsible would need to meet each year's specified carbon intensity level, provided that a regulated party can meet these annual carbon intensity levels with any combination of fuels it produces or supplies and with LCFS credits generated in previous years or acquired from other regulated parties;

Specifically identify who is the regulated party - and when regulated party obligations are or can be transferred downstream - with respect to gasoline, diesel fuel, and other liquid blendstocks (including oxygenates and biodiesel); compressed and liquefied natural gas derived from petroleum sources (fossil compressed natural gas (CNG) and fossil liquefied natural gas (LNG), respectively); other gaseous fuels (biogas/biomethane and hydrogen); and electricity;

An opt-in provision for certain alternative fuels - electricity, hydrogen and hydrogen blends, fossil CNG derived from North American sources, biogas CNG, and biogas LNG - that have full fuel-cycle carbon intensities that inherently meet the proposed compliance requirements through 2020; regulated parties for these fuels would be required to meet the LCFS requirements (e.g., reporting, credit balancing) only if they elect to generate credits based on these fuels as provided under the proposal;

An exemption for any alternative fuel that is not biomass-based or renewable biomass-based and for which the aggregated volume by all parties for that fuel is less than 420 million mega-Joules per year (3.6 million gasoline gallon equivalent per year);

Exclusions for specific applications of transportation fuels, including fuels used in aircraft, racing vehicles, interstate locomotives, ocean-going vessels, and military tactical vehicles;

Establish separate annual carbon intensity schedules for gasoline and diesel transportation fuels from 2011 through 2020 when a 10 percent reduction relative to 2010 would be achieved; gasoline and diesel fuel would follow similar annual carbon intensity reduction curves and the carbon intensity for alternative fuels (e.g., biofuels, natural gas, hydrogen, electricity) would be judged against either the gasoline or diesel carbon intensity requirements, depending on whether the alternative fuel is used for light- and medium-duty vehicles or for heavy-duty vehicles, as specified in the regulation;

Require that each year, the carbon intensity of all transportation fuel for which a regulated party is responsible is compared to the LCFS requirement for that year; fuels that have carbon intensity levels below the requirement generate credits, fuels with carbon intensity levels above the requirement create deficits, and to comply with the LCFS'for a given year, a regulated party must show that the total amount of credits equals or exceeds the deficits incurred (excess credits can be retained or sold to other regulated parties);

Require regulated parties to submit quarterly progress reports, which must contain a specified set of information and data, such as carbon intensities, fuel volumes sold or dispensed, fuel transfer information, and other information;

Require regulated parties to submit annual account-balance reports that include additional information relating to the total credits and deficits generated during the year or carried over from the previous year, total credits acquired from another party, total credits transferred to other parties, credits generated and banked in the current year; and any deficits to be carried into the next year; all quarterly and annual reporting will be done via a web-based, interactive form to be established prior to the implementation of the regulation;

Require that a regulated party that ends a compliance year with a credit balance shortfall greater than 10 percent will be in violation of the LCFS and subject to penalties commensurate with the size of the violation; such a party must also reconcile and remedy the shortfall within a specified period of time;

Require that a regulated party that ends a compliance year with a deficit not exceeding 10 percent will only be required to reconcile the shortfall within the following year, as well as meet the compliance obligations that apply in that year;

To ensure that low carbon fuels and blendstocks produced outside of California are actually the source of finished fuels reported by a regulated party, require regulated parties to establish physical pathway evidence for transportation fuels they report; this could involve a four-part showing including a one-time demonstration that there exists a physical pathway by which the transportation fuel is expected to arrive in California, written evidence (by contract or similar evidence) showing that a specific volume of a particular transportation fuel with known carbon intensity was inserted into the physical pathway as directed by the regulated party, written evidence showing that an equal volume of that transportation fuel was removed from the physical pathway by the regulated party for use as a transportation fuel in California, and an update to the initial physical pathway demonstration whenever there are modifications to the initially demonstrated pathway;

Mandate that the Executive Officer certify the carbon intensity values for various fuel pathways, including multiple pathways for some fuels to represent differences in how and where the fuel is produced; direct emissions associated with producing, transporting, and using a specific fuel would be determined using the CA-GREET model, a modified version of the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model;

For some crop-based biofuel pathways, the certified carbon intensity values would also account for additional GHG emissions that can result from changes in land use arising from use of the biofuels; the Global Trade Analysis Project (GTAP) model is to be used to evaluate the worldwide land use conversion associated with the production of crops for fuel production;

Upon adoption of the LCFS regulation, the. Executive Officer would publish a "Carbon Intensity Lookup Table" identifying the carbon intensity for a number of specific fuel pathways for which the carbon intensity values had been adequately developed for certification; the Executive Officer is authorized to subsequently certify additional or modified carbon intensity values in the Carbon Intensity Lookup Table;

For a regulated party identifying the carbon intensity value of the various fuels it is providing, use of the carbon intensity values in the Carbon Intensity Lookup Table is characterized as "Method 1"; under specified conditions, regulated parties may also obtain Executive Officer approval to either modify the CA-GREET model inputs to reflect their specific processes (Method 2A) or to generate an additional pathway using CA-GREET (Method 2B);

A regulated party must meet a scientific defensibility requirement before the Executive Officer can approve new values under Methods 2A and 2B; for Method 2A, there is an additional provision that requires a substantial change in the carbon intensity relative to the analogous value calculated for that pathway under Method 1;

A regulated party is to use the basic value in the Lookup Table for CARBOB (the blend component into which ethanol is added to produce a final oxygenated gasoline), gasoline and diesel fuel, unless the fuel is produced from crude oils with high carbon intensity relative to the average carbon intensity of crude oils used in California refineries;

For CARBOB, gasoline and diesel fuel produced from high carbon intensity crude oil, the regulated party must use the carbon intensity value, if any, which is specified in the Carbon Intensity Lookup Table for that particular pathway; if there is no carbon intensity value specified for a particular high carbon-intensity crude oil, the regulated party could. use Method 2B (with Executive Officer approval) to generate an additional pathway for this type of crude, or alternately could use the standard Carbon Intensity Lookup Table value - but only if the regulated party can demonstrate to the Executive Officer that its crude production and transport carbon-intensity value has been reduced to a specified level, using carbon-capture and sequestration or other method;

A direction to the Executive Officer to conduct a review of implementation of the LCFS by January 1, 2012, with the scope and content of the review to be determined by the Executive Officer; and

Establish a regulatory mechanism for multimedia evaluations that closely tracks the mechanism in section 43830.8(a) of the Health and Safety Code, and prohibit the sale of a regulated fuel unless a multimedia evaluation of the fuel has been. conducted pursuant to the regulatory mechanism; there would be exceptions for (1) regulated fuels subject to a specification that was adopted by ARB before adoption of the LCFS regulation and that has not been subsequently amended by ARB; (2) regulated fuels that are subject to the Division of Measurement Standards' engine fuels standards but are not subject to an ARB-adopted fuel specification; and (3) regulated fuels for which ARB has proposed a new or amended specification subsequent to adoption of the. LCFS regulation, where the California Environmental Policy Council has conclusively determined. that the new or amended specification will not have any significant adverse impact on public health or the environment.

WHEREAS, ARB staff conducted sixteen public workshops regarding the proposed LCFS throughout California in 2008 and 2009 and also participated in numerous other meetings with various stakeholders in order to include the public and affected stakeholders in the regulatory development process;

WHEREAS, ARB staff has prepared a document entitled "Staff Report: Initial Statement of Reasons (ISOR) for Proposed Regulation to Implement the Low Carbon Fuel Standard" which presents the rationale and basis for the proposed regulation and identifies the data, reports and information relied upon;

WHEREAS, the ISOR and proposed regulatory language were made available to the public for at least 45 days prior to the public hearing to consider the proposed regulation;

WHEREAS, the scientific portions of the proposed regulation and ISOR were reviewed by four peer reviewers pursuant to a Cal/EPA agreement with the University of California; the last of the four peer reviews was received April 12, 2009, and the four reviews are included in the rulemaking record and have been posted on ARB's webpage for this rulemaking;

WHEREAS, the Board has considered the impact of the proposed regulation on the economy of the State and the potential for adverse economic impacts on California business enterprises and individuals;

WHEREAS, the Board has considered the community impacts of proposed regulations, including environmental justice concerns;

WHEREAS, the California Environmental Quality Act, section 21000 et seq. of the Public Resources Code, and Board regulations at California Code of Regulations, title 17, section 60006 require that no project that may have significant adverse environmental impacts be adopted as originally proposed if feasible alternatives or mitigation measures are available to reduce or eliminate such impacts;

WHEREAS, a public hearing and other administrative proceedings have been held in accordance with the provisions of chapter 3.5 (commencing with section 11340), part 1, division 3, title 2 of the Government Code;

WHEREAS, in consideration of the ISOR, written comments, and public testimony it has received, the Board finds that:

> California's transportation sector is the leading source of GHG emissions in the state, contributing almost 40 percent of the state's annual GHG emissions;
>
> The fuel used in cars, trucks and other transportation sources has a significant impact on GHG emissions and reducing the impact these fuels have on GHG emissions will provide important environmental and possibly economic opportunities;
>
> Pursuant to Board Resolution 08-47, there are a number of reasons why GHG emission reductions from transportation fuels are best achieved using the. proposed regulatory approach, as identified below. While California's cap-and-trade program is expected to include upstream coverage of transportation fuels beginning in 2015, a LCFS requirement will complement this coverage, and will: (a) ensure that the GHG emissions from the full fuel lifecycle are accounted for and reduced to the extent feasible; (b) stimulate the development of substantially lower-carbon transportation fuels more directly than including transportations fuels in the cap-and-trade program; (c) achieve long-term reductions in GHG

emissions from transportation fuels; (d) diversify the California fuel pool; and (e) reduce the State's dependence on petroleum;

Staff has performed the complete lifecycle analysis of several fuels including: petroleum-based fuels, biofuels, and other non-liquid fuel alternatives (such as electricity, CNG, and hydrogen) and, has assigned scientifically defensible carbon intensity values to these fuels as detailed in the ISOR;

Indirect land use change has been appropriately included as part of the lifecycle analysis conducted by staff; indirect land use change is not inconsequential to the lifecycle of some crop-based biofuels and to exclude indirect land use effects in the initial LCFS regulation would allow fuels with carbon intensities that are similar to gasoline and diesel fuel to function as low-carbon fuels - delaying the development of truly low-carbon fuels and jeopardizing the achievement of a 10 percent reduction in carbon intensity by 2020;

To the extent the indirect land use values for crop-based biofuels included in the regulation approved herein may be different from values that may be generated in the future based on more robust data and more advanced analytical tools, the approved values are more likely to be lower rather than higher compared to subsequently-generated values;

No other significant indirect effects that result in large GHG emissions have been identified that would substantially affect the LCFS framework for reducing the carbon intensity of transportation fuels;

While there is about a 20 percent improvement in the adjusted carbon intensity of light-duty diesel vehicles using conventional diesel fuel compared to gasoline vehicles, crediting light-duty diesel vehicles for reduced carbon intensity in the regulation is inappropriate because it would not provide any significant long-term benefits of promoting significantly lower carbon fuels and significantly more energy efficient vehicles;

Including a LCFS standard for diesel fuel and its replacements in addition to a standard for gasoline and its replacements is appropriate because including diesel fuel from the beginning will allow for the development of a more robust credit market and will provide greater certainty on future expectations and because elimination of the diesel element would reduce the LCFS benefits by 20 percent;

By the time the regulation approved herein is formally adopted by the Executive Officer, it will include pathways for biodiesel and renewable diesel that could be used in the near term for compliance by providers of diesel fuel choosing to rely on that approach;

The proposed regulation is expected to significantly reduce emissions of GHGs, such as CO2, methane, nitrous oxide, and other GHG contributors from the use of transportation fuels subject to the LCFS; by 2020, the LCFS is expected to reduce GHG emissions from the combustion of transportation fuels in California by about 16 million metric tons of carbon dioxide (16 MMT C02e) annually; the estimated GHG emissions reductions for the full fuel lifecycle, including fuel production through combustion are about 23 MMT C02e in 2020 - a 10 percent reduction of the GHG emissions from the use of transportation fuel, compared to the expected 3 percent reduction in GHG emissions if only the federal RFS2 requirements were met;

While the existing federal RFS2 provides an important and complementary starting point for reducing GHG emissions from transportation fuels, the RFS2 will deliver only about 30 to 40 percent of the GHG benefits of the proposed regulation; the RFS2 does not contain any of the elements of the proposed regulation that incentivize the development of fuels such as natural gas, electricity, or hydrogen that are not biofuels;

If California were to rely solely on the RFS2 to address GHG emissions from transportation sources, the State would not achieve the GHG emission reductions called for in the AB 32 Scoping Plan and Executive Order S-01-07;

The regulation approved herein was developed using the best available economic and scientific information and will achieve the maximum technologically feasible and cost-effective GHG emission reductions from transportation fuel used in California, and encourage early compliance with the proposed requirements;

The GHG emission reductions resulting from the implementation of the regulation approved herein are expected to be real, permanent,. quantifiable, verifiable, and enforceable by ARB, and the proposed regulation complements, and does not interfere with other air quality efforts;

ARB staff evaluated the four peer reviews prepared pursuant to section 57004 of the Health and Safety Code; none of the reviews require major modifications to either the proposed regulation or the analysis used to support the proposal;

The regulation approved herein meets the statutory requirements for a Discrete Early Action Measure under section 38560.5 of the Health and Safety Code and also satisfies the requirements of section 38560 of the Health and Safety Code;

The regulation approved herein meets the criteria set forth in section 38562 of the Health and Safety Code;

The regulation approved herein was developed in an open public process, in consultation with affected parties through numerous public workshops, individual meetings, and other outreach efforts;

The benefits to human health, public safety, public welfare, or the environment justify the costs of the proposed regulation;

The cost-effectiveness of the proposed regulation has been considered, and the regulation will achieve cost-effective GHG emission reductions;

The proposed regulation is consistent with ARB's environmental justice policies and will equally benefit residents of any race, culture or income level;

The reporting requirements of the proposed regulation which apply to businesses are necessary for the health, safety, and welfare of the people of the State;

No reasonable alternative considered, or that has otherwise been identified and brought to the attention of the ARB, would be more effective at carrying out the purpose for which the regulation is proposed or would be as effective and less burdensome to affected private persons and businesses than the proposed regulation; and

Adoption of the LCFS regulation approved herein will not itself constitute establishment of a motor-vehicle fuel specification and therefore does not trigger a multimedia evaluation requirement under Health and Safety Code section 43830.8, for the reasons set forth in the ISOR.

WHEREAS, the Board further finds that: The economic impacts of the proposed regulation have been analyzed as required by California law, and the conclusions and supporting documentation for this analysis are set forth in the ISOR;

The displacement of petroleum-based fuels with lower-carbon-intensity fuels as a result of the proposed regulation is expected to result in an overall savings in the State, as much as $11 billion from 2010-2020; these savings may be realized by the biofuel producers as profit, or some of the savings may be passed on to the consumers - should the savings be entirely passed on to consumers, it would represent less than three percent of the total cost of a typical gallon of transportation fuel ($0 - $0.08/gal);

The economic analysis of the proposed LCFS is greatly affected by future oil prices and the actual production costs and timing of lower-carbon-intensity alternative fuels; economic factors such as tight supplies of lower carbon-intensity fuels or a lengthy economic downturn keeping crude oil demand and hence prices down could result in overall net costs, rather than savings, from the LCFS;

The economic analysis of the proposed LCFS includes federal biofuel tax credits, which is appropriate, as the economic analysis was conducted on a cost-of-compliance basis;

The proposed regulation does not mandate the use of advanced technology vehicles; therefore, the marginal cost of these vehicles over conventional vehicles is not included in the economic analysis;

The proposed regulation is not expected to affect small businesses because: (1) most, if not all, regulated parties are anticipated to be relatively large businesses, and (2) small businesses (generally the fueling station owners and operators) would presumably invest in equipment that dispenses LCFS-compliance fuel with the expectation that the costs of such an investment would be recouped through the sale of such fuels;

The proposed regulation would create costs to the State in the form of lost transportation-fuel taxes, including excise taxes and sales tax; although there would be not estimated fiscal impact for the first three years of the proposed regulation, staff estimates the potential loss of annual state tax revenue to be $80 million to $370 million in 2020 - the year of greatest impact - depending on the compliance paths chosen; and

For local government, the impact of sales tax on transportation fuels from implementing the potential compliance scenarios could either create revenue or result in a revenue loss, depending on the compliance paths chosen, and the impact to local sales taxes would be location specific; although there would be no fiscal impact for the first three years, staff estimates a potential range of impacts in annual local sales tax revenue of -$51 to +$2 million from 2013-2020.

WHEREAS, pursuant to the requirements of the California Environmental Quality Act (CEQA) and the Board's regulations, the Board further finds that:

Overall, the proposed regulation is expected to result in no significant additional adverse impacts to California's statewide air quality due to emissions of criteria and toxic pollutants; based on the best available data, there may be a benefit in further reducing criteria pollutants from the 2020 projected vehicle fleet;

However, as described below, there may be some small but potentially significant adverse impacts on a localized or regional basis from the construction and operation of biorefineries, as identified below;

The demand for feedstocks needed to comply with the proposed regulation may support approximately 25 additional "biorefineries" - ethanol, biodiesel, and renewable hydrocarbon production facilities - in California; the actual number and siting of these facilities is dependent upon many factors, including the location of the feedstock and the need to sufficiently mitigate environmental impacts pursuant to CEQA and obtaining necessary permits, including permits from local air pollution control and air quality management districts (local districts);

Depending on the specific local district, permitting rules for siting new biorefineries in the State will likely require best available control technology and offsets for criteria pollutants, and an analysis of the localized toxic air pollutant impacts; these determinations will be made on a case-by-case basis with facility specific information;

In general, any direct emissions from new biorefineries are likely to be mitigated as part of the CEQA process and local air district permitting actions; accordingly, no significant adverse impacts on a regional basis are expected as a result of direct emissions from these facilities. While some increases in localized emissions could occur, staffs analysis has not identified any significant criteria or toxic air pollutant impacts from direct biorefinery emissions that cannot be mitigated through local actions (e.g., through requirements to apply best available control technologies);

Some increases in localized emissions may occur due to additional truck trips to and from new biorefineries. Such increased criteria pollutant emissions may be offset on a statewide basis by reductions in motor vehicle emissions; however, there may still be localized diesel PM impacts and localized facility emissions impacts;

Staff's health risk assessment of the potential cancer risk associated with newly established biorefineries shows the highest risk associated with onsite diesel PM emissions from three, hypothetically co-located prototype biorefinery facilities, with the area of greatest impact estimated to be the area surrounding the facility fence lines with a potential cancer risk of over 0.4 changes in a million; an examination of combined onsite and offsite emissions from the three prototype biofuel facilities showed the area with the greatest impact estimated to have a potential cancer risk of five chances in a million;

Staff also quantified seven non-cancer health impacts associated with the change in exposure to PM2.5 emissions due to the operation of biofuel facilities, with the statewide health impacts of the emissions associated with the LCFS being approximately 24 premature deaths, 8 hospital admissions, and 367 cases of asthma, acute bronchitis and other lower respiratory symptoms;

In addition to the potential impacts on air quality, the ISOR contains an assessment of other potential environmental impacts that might result from the implementation of the LCFS, including potential impacts on water quality and water use, agricultural resources, biological resources, hazardous waste and hazardous materials, solid waste, and transportation and other traffic, among others;

Some new California biorefineries could use significant amounts of water that could result in significant impacts; since all new facilities would need to meet CEQA and agency permitting requirements, including requirements of the California Regional Water Quality Control Boards, the final determination of impacts on water would need to be made on a site-specific basis;

The LCFS will provide some additional incentives to use grid-powered batteries in plug-in hybrid vehicles and battery electric vehicles; this increase is not expected to have a significant adverse environmental impact on landfills because the disposal of such batteries is already subject to extensive regulation in the State, and automotive batteries are among the most highly recycled products today;

The emissions and water use increases described above are small, but could nevertheless constitute an adverse environmental impact;

The ISOR does not identify any other significant impact that would not otherwise be mitigated through agency permitting or CEQA compliance;

As noted, the potential adverse impacts identified above are expected to be mitigated through the CEQA process and local air district permitting actions;

Except for the emissions impacts and water use impacts described above, there are no significant adverse environmental impacts that will occur from the proposed LCFS regulation;

The Executive Officer' is the decision maker for the purposes of title 17, California Code of Regulations, section 60007 and responding to environmental issues raised on the proposed regulation, and by approving this Resolution 09-31, the Board is not prejudging any of the responses that will be made by the Executive Officer to these environmental issues;

The proposed LCFS regulation is necessary in order to protect public health by substantially reducing GHG emissions resulting from the full fuel lifecycle of transportation fuels in California;

The potential adverse environmental impacts of the proposed LCFS regulation are outweighed by the substantial reduction in GHG emissions and public health benefits that will result from the proposed regulation's adoption and implementation;

The considerations identified above override any adverse environmental impacts that may occur from adoption and implementation of the proposed LCFS regulation; and

The Board has considered alternatives to the proposed regulation and has identified no feasible mitigation measures or alternatives available to the Board that would further substantially reduce the potential adverse impacts of the proposed regulation, as identified above, while at the same time ensuring that the necessary the GHG emission reductions noted herein will be achieved.

NOW, THEREFORE, BE IT RESOLVED that the Board hereby approves for adoption new sections 95480, 95480.1, 95481, 95482, 95483, 95484, 95485, 95486, 95487, 95488, and 95489 of subarticle 7, article 4, subchapter 10, chapter 1 of division 3, title 17, CCR, as set forth in Attachment A hereto, with the modifications described in Attachment B hereto.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer: (1) to incorporate into the approved regulations and incorporated document the modifications described in Attachment B hereto and such other conforming modifications as may be appropriate; (2) to make the modified regulations (with the modifications clearly identified) and any additional documents or information available for public comment for a period of at least 30 days; (3) to consider any comments on the modifications received during the supplemental comment period; and then (4) either to adopt the regulations as made available with any appropriate additional nonsubstantial modifications, to make additional modifications available for public comment for an additional period of at least 15 days, or to present the regulations to the Board for further consideration if he determines that this is warranted.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with interested stakeholders to prepare guidelines to assist regulated parties in determining the data, documentation, and other information needed to support the expeditious

development of carbon intensity values for new or modified fuel pathways. For biofuel pathways, the guidelines should provide for consideration, to the extent feasible, of the impacts on direct and indirect land-use change emissions from factors including, but not limited to: productivity of biofuel per acre of land; water use; low carbon agricultural practices that improve the carbon sequestration in soil; and creation of protein and electricity co-products. The Executive Officer should present these guidelines to the Board by December 2009.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with biofuel producers and other interested stakeholders to identify specialized fuel pathways such as anaerobic digestion, thermochemical conversion of biomass feedstocks and additional liquefied natural gas pathways that the Board staff will develop and propose for incorporation into the Carbon Intensity Lookup Table. The prioritized list, with a proposed development schedule, shall be presented to the Board by December 2009.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to convene an expert workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified. This workgroup should evaluate key factors that might impact the land use values for biofuels including agricultural yield improvements, co-product credits, land emission factors, food price elasticity, and other, relevant factors. The Executive Officer shall coordinate this effort with similar efforts by the U.S. EPA, European Union, and other agencies pursuing a low carbon fuel standard.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with interested stakeholders to develop criteria and a list of specific biofuel feedstocks that are expected to have no or inherently negligible land use.effects on carbon intensity and to propose amendments, if appropriate, to the regulation resulting from this analysis by December 2009.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with interested stakeholders to develop an informal screening process for assessing the carbon intensity of new or modified fuel pathways. The Executive Officer should present an update on the progress on this process to the Board by the end of December 2009.

BE IT FURTHER RESOLVED that, pursuant to sections 39515, 39516, 39600, and 39601 of the Health and Safety Code, the Board delegates to the Executive Officer the authority to conduct and complete rulemakings to (a) add new or customized fuel pathways and carbon intensity values to the Carbon Intensity Lookup Table in section 95486, (b) revise any existing fuel pathway or carbon intensity value (except

values based on land use or other indirect effects that are specified in the Carbon Intensity Lookup Table in section 95486 as adopted in this rulemaking), and (c) revise the incorporated GREET model as newer versions become available. The Board directs the Executive Officer to notify the Board of the initiation and results of any rulemakings conducted pursuant to this delegation.

BE IT FURTHER RESOLVED that, pursuant to sections 39515, 39516, 39600, and 39601 of the Health and Safety Code, the Board delegates to the Executive Officer the authority to conduct and complete rulemakings to amend any portion of the table specifying the Energy Economy Ratios (EER) in section 95485(a), including but not limited to, adding a new EER or revising an existing EER. The Board directs the Executive Officer to notify the Board of the initiation and results of any rulemakings conducted pursuant to this delegation.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to specifically re-evaluate the EER for heavy-duty vehicles fueled by compressed and liquefied natural gas and, if appropriate, to update the EER as soon as practical.

BE IT FURTHER RESOLVED that, pursuant to sections 39515, 39516, 39600, and 39601 of the Health and Safety Code, the Board delegates to the Executive Officer the authority to conduct and complete a rulemaking to add to or amend the list of opt-in, low-carbon fuels specified in section 95480.1(b). The Board directs the Executive Officer to notify the Board of the initiation and results of any rulemakings conducted pursuant to this delegation.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with petroleum refiners, biodiesel and renewable diesel producers, and other stakeholders to complete the ongoing multimedia evaluation for biodiesel and renewable diesel; and propose, as appropriate, motor-vehicle fuel specifications for biodiesel and renewable diesel by December 2009.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with the Interagency Forest Work Group (IFWG), the California Natural Resources Agency, the California Energy Commission, the California Department of Forestry and Fire Protection, the United States Forest Service, the U.S. EPA, environmental advocates, regulated parties, and other stakeholders to further develop definitions and safeguards for the use of "biomass" and "renewable biomass," and propose amendments to the LCFS regulation, if appropriate, by December 2009. As part of this effort, the Board further directs the Executive Officer to consider the specific effects of incentivizing the use of forest biomass from public and private lands; the greenhouse gas emissions from different fuel pathways on public and private lands; and the additional protections, if any, necessary to ensure the sustainable and environmentally beneficial use of such forest biomass, with the goal of certifying pathways for the use of forest biomass.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with IFWG, appropriate state agencies, environmental advocates, regulated parties, and other interested stakeholders to present a workplan to the Board by December 2009 for developing sustainability provisions to be used in implementing the LCFS regulation. The workplan should include, but not be limited to, a science-based definition of sustainability; how the sustainability provisions can incentivize sustainable fuels; what provisions will be reviewed for inclusion in the LCFS regulation; the framework for how sustainability provisions could be incorporated and enforced in the LCFS program; and a schedule for finalizing sustainability provisions by no later than December 2011, unless the Executive Officer determines that such actions are not feasible and not appropriate.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with local air districts, regulated parties, environmental advocates, public health experts and other stakeholders to develop a "best practices" guidance document for use by siting authorities when they are considering the siting of biofuel and other fuel production facilities in California to assess and mitigate the air quality impacts of these facilities and to present the guidance document to the Board by December 2009.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to continue to work with the California Public Utilities Commission, electric utilities, oil refiners, and other stakeholders to review the provisions applicable to regulated parties for electricity and propose amendments, if appropriate, to the regulation by December 2009.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with electric utilities, environmental advocates, and other stakeholders to further evaluate the feasibility of generating credits for electricity used in nonroad transportation sources, such as new categories and applications of electric forklifts and other similar nonroad vehicles and equipment, and propose amendments, if appropriate, to the regulation by December 2009.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer, as part of the development of the cap-and-trade regulation identified in ARB's AB 32 Scoping Plan and other AB 32 activities, to: (1) evaluate as part of the cap-and-trade rulemaking whether displacing petroleum transportation fuels with electricity leads to a cross-sector shift in GHG compliance obligations and assesses the effect of any such shift, including the impacts on electricity use as a transportation fuel and attendant price signals on consumers; and (2) consider as part of the ongoing activities associated with AB 32 how the LCFS regulation, a broader cap-and-trade regulation, and other programs established pursuant to the AB 32 Scoping Plan should work together to ensure that the use of electricity as a transportation fuel is appropriately encouraged consistent with the goals of AB 32.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to work with stakeholders to develop a fee schedule; credit trading provisions; and robust, transparent, and specific criteria for conducting Carbon Intensity Lookup Table modifications through a certification process, and propose amendments to the regulation, if appropriate, at the December 2009 hearing.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to use a public process, open to all stakeholders, to address the specific provisions in this resolution and to coordinate efforts, to the extent feasible, with the U.S. EPA, the European Union, and other regional, national and international agencies considering the adoption and implementation of an LCFS regulation or similar programs.

BE IT FURTHER RESOLVED that, for projects in California directly related to the production, storage and distribution of transportation fuel subject to the LCFS program, the Board directs the Executive Officer to participate in the environmental review of specific projects; evaluate the air quality impacts of these projects; and, as appropriate, identify feasible measures to mitigate the local and regional impacts of the projects. This effort is to be coordinated with the local air districts; lead agencies for the preparation of environmental impact reports to comply with the California Environmental Quality Act; companies proposing to build new production, storage and distribution facilities; and environmental and community representatives.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to monitor the implementation of the regulation and to propose amendments to the regulation for the Board's consideration when warranted.

I hereby certify that the above is a true and correct copy of Resolution 09-31, as adopted by the Air Resources Board.

Resolution 09-31

April 23, 2009

Identification of Attachments to the Board Resolution

Attachment A: Proposed Regulation to Implement the Low Carbon Fuel Standard, as set forth in Appendix A to the Initial Statement of Reasons, released March 5, 2009.

Attachment B: Staff's Suggested Modifications to the Original Proposal, presented at the April 23, 2009 public hearing.

APPENDIX B

LIST OF WORKING GROUP MEMBERS

Barrett, Will	American Lung Association
Carrari, Louis	Air Resources Board
Chen, Jay	South Coast Air Quality Management District
DeGuzman, Jorge	Sacramento Metropolitan Air Quality Management District
Eden, Rudy	South Coast Air Quality Management District
Gill, Sheraz	San Joaquin Valley Air Pollution Control District
Holmes-Gen, Bonnie	American Lung Association
Howard, Kitty	Air Resources Board
Lapis, Nick	Californians Against Waste
Liebel, Thomas	South Coast Air Quality Management District
Merkel, Loula	Coskata, Inc.
Millican, Rodney	South Coast Air Quality Management District
O'Connor, Tim	Environmental Defense Fund
Powers, Evan	Air Resources Board
Prasad, Shankar	Coalition for Clean Air
Shears, John	The Center for Energy Efficiency and Renewable Technologies
Smithline, Scott	Californians Against Waste
Sumait, Necy	Blue Fire Ethanol
Thaeler, Jordan	Amyris
Tupac, Charles	South Coast Air Quality Management District
Valla, Art	Bay Area Air Quality Management District
Violet, Alicia	Air Resources Board
Warner, Dave	San Joaquin Valley Air Pollution Control District
White, Chuck	Waste Management, Inc.
Wilson, Hubert	South Coast Air Quality Management District
Yamashita, Lea	Air Resources Board

APPENDIX C

Biomass Feedstocks Available for Biofuel Production

Sector	Category	Description
Agricultural	Slaughter	Packing house and butcher shop tissue and bone from cattle, poultry, sheep, swine, goats, and horses; poultry feathers; dead stock (whole animals)
	Manure and bedding	Manure from confined animal facilities (cattle, poultry, sheep, swine, goats, and horses); spent bedding; litter
	Orchard and vine	Pruning and tree/vine removal
	Field, seed, and vegetable	Grain straws and corn stover; vegetable crop materials that are incorporated into soil and not used off-field
	Food processing	Nut shells; fruit pits; rice hulls; cotton gin trash; grape, tomato, and beet pomace; cheese whey; spent grains and yeast
Forestry	Logging and forest thinning	Branches, tops, and other material removed from trees during timber harvest, non-marketable components (understory brush, small diameter boles, other material that cannot produce saw logs)
	Sawmill	Byproduct of milling saw logs (bark, sawdust, planer shavings, trim ends)
	Shrub or chaparral	Shrubby evergreen plants
Urban	Municipal solid waste (MSW)	Food and kitchen waste, restaurant grease, grass, landscape tree removal, other green waste, paper, construction and demolition material.
	Medical	Solid waste generated in the diagnosis, treatment, or immunization of humans or animals
	Biosolid	Organic material from treatment of sewage sludge or wastewater
Dedicated Energy Crops	Seed and grain crops	Crops grown specifically for the production of biofuel in California (corn, sugarcane, soy, poplar trees, and switchgrass).

APPENDIX D

SUPPORTING DATA FOR MOST STRINGENT EMISSION LIMITS IDENTIFIED FOR STATIONARY SOURCE PROCESS EQUIPMENT USED AT BIOREFINERIES

Table Notes:

(1) Calculated values, in *italics*, are shown for comparative purposes.
(2) Calculated VOC values are calculated as methane unless otherwise specified.
(3) N/A indicates that BACT was not triggered, or the rule, guideline, or policy does not cover that particular pollutant.
(4) F factor for waste gas is assumed to be 9,570 dscf/MMBtu.
(5) Efficiency for reciprocating IC engines is assumed to be 35%.
(6) SCAQMD BACT Clearinghouse is organized such that guidelines for non-major facilities are contained in Part D and guidelines for major facilities are included in Part B. For major sources in the District, the project proponent should not automatically assume it will meet District BACT requirements if proposed emission levels are consistent with Part D guidelines. The project proponent should check the Part B guidelines and consult with District permitting staff.

Table D-1. Grain Receiving, Conveying, Grinding, and Storage Operations

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	Pacific Ethanol; Brawley, CA	Biomass fuel receiving, handling, and storage		Permit	2007					Baghouse w/ 99% control
2	SJVAPCD Guideline 6.4.5[1]	Biomass fuel receiving, handling, and storage		BACT (AIP)	9/7/1998					Use of wet suppression system on all emission units, transfer points, and raw material stockpiles to maintain moisture to prevent visible emissions >20%

[1] Based on Chrysler Corp., Mendota, CA.

Table D-1. Grain Receiving, Conveying, Grinding, and Storage Operations

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
3	SCAQMD Guidelines for Non-Major Facilities	Bulk solid material handling – other (feed and grain handling)		BACT	1988					Baghouse
4	SCAQMD Guidelines for Non-Major Facilities	Bulk solid material handling – other (pneumatic conveying, except paper and fiber)		BACT	1988					Baghouse
5	SCAQMD Guidelines for Non-Major Facilities	Bulk solid material handling – other (other dry materials handling)		BACT	7/11/1997					Enclosed conveyors and baghouse
6	SCAQMD Guidelines for Non-Major Facilities	Bulk solid material handling – other (other wet materials handling)		BACT	1988					Water spray or adequate material moisture

Table D-2. Methanol/Sodium Methoxide Receiving and Storage

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	American Biodiesel, Inc. dba Community Fuels; Stockton, CA		Vapor recovery system	Permit	6/4/2007			99.5% control		
2	Blue Sky Bio-Fuel, Inc.; Oakland, CA		Vapor balance system	Permit				95% control		
3	Crimson Renewable Energy, LP; Bakersfield CA		Vapor control system	Permit	12/13/2008			95% control		

Table D-2. Methanol/Sodium Methoxide Receiving and Storage										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
4	Golden Gate Petroleum Company; San Jose, CA		Vapor balance system	Permit				95% control		

Table D-3. Fermentation Process: Yeast, Liquefaction, Beerwell, and Process Condensate Tanks										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	Pacific Ethanol; Madera, CA	Ethanol fermentation process tanks	Wet scrubber to Regenerative Thermal Oxidizer	Source test	2/20/2007			>99.9% control		
2	Phoenix Bio Industries, LLC; Goshen, CA	Ethanol fermentation process tanks including fermentation tanks and beerwell storage tanks	Wet scrubber vented to CO_2 wet scrubber w/ Regenerative Thermal Oxidizer	Source test	4/18/2007			99.7% control		
3	SJVAPCD Guideline 4.12.4[2]	Ethanol fermentation process tanks including fermentation tanks and beerwell storage tanks		BACT (AIP)	2/17/2004			99.5% VOC control efficiency (fermentation wet scrubber vented to CO_2 recovery plant w/ condenser and high pressure scrubber, or equivalent)		

[2] Based on Pacific Ethanol, Madera, CA.

Table D-4. Distillation and Wet Cake Processes

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	Pacific Ethanol; Madera, CA	Ethanol distillation process	Distillation wet scrubber	Source test	2/20/2007			>99% control		
2	Calgren Renewable Fuels; Pixley, CA	Emissions units involved in ethanol distillation and wet cake process (excluding wet cake dryer)	Distillation wet scrubber w/ regenerative thermal oxidizer	Authority to Construct	7/7/2005			95% VOC control		
3	Calgren Renewable Fuels; Pixley, CA	Emissions units involved in ethanol distillation and wet cake process (excluding wet cake dryer)	Distillation wet scrubber w/ regenerative thermal oxidizer	Source test	1/12/2010			>99.9% VOC control		
4	Pacific Ethanol; Madera, CA	Emissions units involved in ethanol wet cake process (excluding wet cake dryer)	Distillation wet scrubber	Permit	(Authority to Construct issued in 2005)			95% control		
5	Pacific Ethanol; Madera, CA	Emissions units involved in ethanol wet cake process (excluding wet cake dryer)	Distillation wet scrubber	Source test	1/25/2008			>99% control		
6	SJVAPCD Guideline 4.12.5[3]	Emissions units involved in ethanol distillation and wet cake process (excluding wet cake dryer)	Wet scrubber or equivalent	BACT (AIP)	2/17/2004			95% VOC control		

[3] Based on Pacific Ethanol, Madera, CA.

Table D-5. Natural Gas-Fired Boiler

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	SJVAPCD Rule 4307 Boilers, Steam Generators, and Process Heaters – 2.0 MMBtu/hr to 5.0 MMBtu/hr	Units 2.0 MMBtu/hr to ≤5.0 MMBtu/hr		Rule	Last amended 10/16/2008	Atmospheric units: 12 ppmvd @ 3% O_2 or 0.014 lb/MMBtu Non-atmospheric units: 9 ppmvd @ 3% O_2 or 0.011 lb/MMBtu	400 ppmvd @ 3% O_2 *(0.296 lb/MMBtu)*	N/A	N/A	N/A
2	SCAQMD Rule 1146.1 Emissions of Oxides of Nitrogen from Small Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	Units >2 MMBtu/hr to <5 MMBtu/hr		Rule	Last amended 9/5/2008	Atmospheric units: 12 ppm @ 3% O_2 or 0.015 lb/MMBtu Non-atmospheric units: 9 ppmvd @ 3% O_2 or 0.011 lb/MMBtu	N/A	N/A	N/A	N/A
3	La Paloma Generating Company, LLC; McKittrick, CA	6.2 MMBtu/hr natural gas boiler	Low NOx burner	BACT (AIP)	3/24/2000	12 ppmv @ 3% O_2 *(0.0146 lb/MMBtu)*	50 ppmv @ 3% O_2 *(0.037 lb/MMBtu)*	30 ppmv @ 3% O_2 *(0.0127 lb/MMBtu)*	N/A	0.007 lb/MMBtu

Table D-5. Natural Gas-Fired Boiler

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
4	SJVAPCD Rule 4306 Boilers, Steam Generators, and Process Heaters – Phase 3	Units >5 MMBtu/hr to ≤20.0 MMBtu/hr (non-refinery units, non-load following units, units not subject to fuel use restriction)		Rule	Last amended 10/16/2008	Standard Option: 15 ppmvd @ 3% O_2 or 0.018 lb/MMBtu Enhanced Option: 9 ppmvd @ 3% O_2 or 0.011 lb/MMBtu	400 ppmvd @ 3% O_2 *(0.296 lb/MMBtu)*	N/A	N/A	N/A
5	SCAQMD BACT Guidelines – Part D	<20 MMBtu/hr natural gas or propane fired boiler	Ultra low NOx burner, or equal	BACT	10/20/2000 (NOx, SOx), 4/10/1998 (CO, PM10)	≤12 ppmvd @ 3% O_2 *(0.015 lb/MMBtu)*	Firetube type: ≤50 ppmvd @ 3% O_2 *(0.037 lb/MMBtu)* Watertube type: ≤100 ppmvd @ 3% O_2 *(0.074 lb/MMBtu)*	N/A	Natural gas	Natural gas
6	BAAQMD Regulation 9 Rule 7 NOx and CO from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	20 MMBtu/hr to <75 MMBtu/hr gaseous fuel-fired boiler		Rule	Last amended 7/30/2008	9 ppmvd @ 3% O_2 *(0.011 lb/MMBtu)*	400 ppmvd @ 3% O_2 *(0.296 lb/MMBtu)*	N/A	N/A	N/A

Table D-5. Natural Gas-Fired Boiler										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
7	SJVAPCD Rule 4306 Boilers, Steam Generators, and Process Heaters – Phase 3	Units >20.0 MMBtu/hr (non-refinery units, non-load following units, units not subject to fuel use restriction)		Rule	Last amended 10/16/2008	Standard Option: 9 ppmvd @ 3% O_2 or 0.011 lb/MMBtu Enhanced Option: 6 ppmvd @ 3% O_2 or 0.007 lb/MMBtu	400 ppmvd @ 3% O_2 *(0.296 lb/MMBtu)*	N/A	N/A	N/A
8	SCAQMD BACT Guidelines – Part D	≥20 MMBtu/hr natural gas or propane fired boiler	Ultra low NOx burner or equal; SCR or equal	BACT	10/20/2000 (NOx, SOx), 4/10/1998 (CO, PM10)	With low NOx burner: ≤9 ppmvd @ 3% O_2 *(0.011 lb/MMBtu)* With add-on controls: ≤7 ppmvd @ 3% O_2 *(0.009 lb/MMBtu)* NH_3: ≤5 ppmvd @ 3% O_2	Firetube type: ≤50 ppmvd @ 3% O_2 *(0.037 lb/MMBtu)* Watertube type: ≤100 ppmvd @ 3% O_2 *(0.074 lb/MMBtu)*	N/A	Natural gas	Natural gas
9	SJVAPCD (Facility unknown)	>20 MMBtu/hr natural gas fired boiler	Ultra low NOx burner or equal	BACT (AIP)	6/30/1999	9 ppmv @ 3% O_2 or 0.0108 lb/MMBtu	N/A	N/A	N/A	N/A

Table D-5. Natural Gas-Fired Boiler

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
10	SJVAPCD (Facility unknown)	≥5 MMBtu/hr steam generator		BACT (AIP)	5/24/2004	14 ppmv @ 3% O_2 *(0.017 lb/MMBtu)*	50 ppmv @ 3% O_2 *(0.037 lb/MMBtu)*	Gaseous fuels	Natural gas, LPG, waste gas treated to remove 95% by weight of sulfur compounds or treated such that the sulfur content does not exceed 1 gr/100 scf, or use of a continuously operating SO_2 scrubber and either achieving 95% by weight control of sulfur compounds or achieving an emission rate of 30 ppmvd SO_2 at stack O_2	Natural gas, LPG, waste gas treated to remove 95% by weight of sulfur compounds or treated such that the sulfur content does not exceed 1 gr/100 scf, or use of a continuously operating SO_2 scrubber and either achieving 95% by weight control of sulfur compounds or achieving an emission rate of 30 ppmvd SO_2 at stack O_2

Table D-5. Natural Gas-Fired Boiler										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
11	BAAQMD BACT Guideline 17.3.1	≥50 MMBtu/hr	Ultra low NOx burner + FGR, good combustion practice	BACT (AIP)	9/22/2005	9 ppmvd @ 3% O_2 *(0.011 lb/MMBtu)*	50 ppmv @ 3% O_2 *(0.037 lb/MMBtu)*	N/A	Natural gas or treated refinery gas fuel w/ <100 ppmv total reduced sulfur	Natural gas or treated refinery gas fuel
			SCR + low NOx burners + FGR, oxidation catalyst	BACT (tech. feasible)		7 ppmvd @ 3% O_2 *(0.009 lb/MMBtu)*	For units ≥250 MMBtu/hr: 10 ppmvd @ 3% O_2[4] *(0.007 lb/MMBtu)*		Natural gas or treated refinery gas fuel w/ <50 ppmv H_2S and <100 ppmv total reduced sulfur	
12	SCAQMD Rule 1146 Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	Units ≥5 MMBtu/hr (excluding electric utility boilers, >40 MMBtu/hr boilers and process heaters used in petroleum refineries, sulfur plant reaction boilers)		Rule	Last amended 9/5/2008	≥5 to <75 MMBtu/hr: 9 ppm @ 3% O_2 or 0.011 lb/MMBtu ≥75 MMBtu/hr: 5 ppm @ 3% O_2 or 0.0062 lb/MMBtu	N/A	N/A	N/A	N/A
13	CalResources; Western Kern County Oil Fields, CA	62.5 MMBtu/hr natural gas boiler	FGR and O_2 controller	BACT (AIP)	11/30/1993	0.036 lb/MMBtu *(30 ppmvd @ 3% O_2)*	0.02 lb/MMBtu *(27 ppmvd @ 3% O_2)*	0.003 lb/MMBtu *(7 ppmvd @ 3% O_2)*	0.0006 lb/MMBtu	0.005 lb/MMBtu

[4] CO limit does not apply to boilers smaller than 250 MMBtu/hr unless an oxidation catalyst is found to be cost effective or is necessary for TBACT or VOC control.

Table D-5. Natural Gas-Fired Boiler

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
14	BAAQMD Regulation 9 Rule 7 NOx and CO from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters	≥75 MMBtu/hr gaseous fuel-fired boiler		Rule	Last amended 7/30/2008	5 ppmvd @ 3% O_2 *(0.006 lb/MMBtu)*	400 ppmvd @ 3% O_2 *(0.296 lb/MMBtu)*	N/A	N/A	N/A
15	Berry Petroleum; Heavy Oil Central, SJVAPCD, CA	84 MMBtu/hr boiler	SCR, low NOx burner	BACT (AIP): SOx, PM10, VOC BACT (tech. feasible): NOx	3/11/2005	With SCR: 7 ppmvd @ 3% O_2 *(0.009 lb/MMBtu)*; With low NOx burner: 9 ppmvd @ 3% O_2 *(0.0109 lb/MMBtu)*	N/A	Natural gas, treated waste gas or recovered gas as a primary fuel. LPG as backup fuel	Natural gas, treated waste gas or recovered gas as a primary fuel. LPG as backup fuel	Natural gas, treated waste gas or recovered gas as a primary fuel. LPG as backup fuel
16	Genentech, Inc.; San Mateo, CA	97 MMBtu/hr Nebraska Model NS-E-64-ST-CA-HM-AL natural gas watertube boiler	Ultra low NOx burner	BACT	9/27/2005 (startup: 6/14/2006)	9 ppmvd @ 3% O_2 *(0.011 lb/MMBtu)*	50 ppmv @ 3% O_2 *(0.037 lb/MMBtu)*	N/A	N/A	N/A
17	AES Huntington Beach; Huntington Beach, CA	2,088 MMBtu/hr natural gas boiler	Low NOx burners, FGR, SCR, oxidation catalyst	BACT (AIP)	2/1/2006	5 ppmvd @ 3% O_2 *(0.006 lb/MMBtu)*	5 ppmvd @ 3% O_2 *(0.004 lb/MMBtu)*	1354 lb/mo	0.2 lb/MMBtu *(120 ppmvd @ 3% O_2)*	0.01 gr/scf @ 12% CO_2

Table D-5. Natural Gas-Fired Boiler

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit NOx	CO	VOC	SO_2	PM10
18	SJVAPCD Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters with a Total Rated Heat Input Greater than 5.0 MMBtu/hr	Units >5.0 to ≤20.0 MMBtu/hr[5]		Rule	10/16/2008	Standard Schedule: 9 ppmvd @ 3% O_2 or 0.011 lb/MMBtu Enhanced Schedule: 6 ppmvd @ 3% O_2 or 0.007 lb/MMBtu	400 ppmvd @ 3% O_2 *(0.296 lb/MMBtu)*	N/A	N/A	N/A
		Units >20.0 MMBtu/hr				Standard Schedule: 7 ppmvd @ 3% O_2 or 0.008 lb/MMBtu Enhanced Schedule: 5 ppmvd @ 3% O_2 or 0.0062 lb/MMBtu				

[5] The NOx limits listed here do not apply to oilfield steam generators, refinery units, units with fuel use restrictions, units at wastewater treatment facilities firing on <50% by volume PUC quality gas, and units operated by a small producer where each burner <5 MMBtu/hr but the total rating is 5-20 MMBtu/hr. See rule for additional restrictions.

Table D-6. Biomass-Fired Boiler

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit: NOx	CO	VOC	SO_2	PM10
1	Musco Olive Products; Tracy, CA	25 MMBtu/hr combined Solar Technologies Model Steamboy fluidized bed boiler producing 3 MW	FGR, SCR, catalyst PM control system (cyclone or in-line bag filter upstream of SCR), baghouse	Authority to Construct	10/2/2009	17.5 ppmvd @ 3% O_2 *(0.023 lb/MMBtu)* NH_3 slip: 10 ppmvd @ 3% O_2	183 ppmvd @ 3% O_2 *(0.144 lb/MMBtu)*	0.02 lb/MMBtu *(45 ppm @ 3% O_2)*	23 ppmvd @ 3% O_2 *(0.041 lb/MMBtu)*	0.045 lb/MMBtu *(0.002 gr/scf @ 12% CO_2)*
2	Massachusetts Department of Environmental Protection BACT Guidance for Biomass Projects	Solid biomass fuel-fired steam electric generating units, ≥1 to <10 MW		BACT (AIP)	4/18/2007[6]	0.093 lb/MMBtu *(72 ppm @ 3% O_2)* NH_3 slip: 25 ppm @ 3% O_2	0.25 lb/MMBtu *(320 ppm @ 3% O_2)*	0.01 lb/MMBtu *(22 ppm @ 3% O_2)*	0.025 lb/MMBtu *(14 ppm @ 3% O_2)*	Filterable: 0.012 lb/MMBtu *(0.006 gr/scf @ 12% CO_2)*
				BACT (tech. feasible)		0.093 lb/MMBtu *(72 ppm @ 3% O_2)* NH_3 slip: 10 ppm @ 3% O_2	0.25 lb/MMBtu *(320 ppm @ 3% O_2)*	0.01 lb/MMBtu *(22 ppm @ 3% O_2)*	0.02 lb/MMBtu *(11 ppm @ 3% O_2)*	Filterable: 0.012 lb/MMBtu *(0.006 gr/scf @ 12% CO_2)*

[6] The guidance indicates it expired on December 31, 2009, and prior to expiration, MassDEP would review its experience with the guidance and initiate a public discussion to determine next steps, such as affirming and/or revising the guidance, or proposing regulations to codify biomass performance standards. According to MassDEP staff, other matters have taken precedence and the public process to update or revise the guidance has not been initiated. However, the guidance is still valid and continues to be available to the public on the MassDEP website at: http://www.mass.gov/dep/air/laws/policies.htm.

Table D-6. Biomass-Fired Boiler

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
3	Rio Bravo; Fresno, CA	352 MMBtu/hr circulating fluidized bed boiler with steam turbine producing 24.3 MW	SNCR, ESP	Permit	2009	0.08 lb/MMBtu (*62 ppmvd @ 3% O_2*); 27.5 lb/hr	22.0 lb/hr; 0.06 lb/MMBtu ; 400 ppmv @ 3% O_2; 310 ppmv @ 12% CO_2 and 7% O_2	10.4 lb/hr; 0.03 lb/MMBtu	10.0 lb/hr; 0.2% by volume	Filterable: 0.01 gr/dscf @ 12% CO_2; 5.8 lb/hr, 0.02 lb/MMBtu Condensable : 17.4 lb/hr; 0.05 lb/MMBtu
4	Massachusetts Department of Environmental Protection BACT Guidance for Biomass Projects	Solid biomass fuel-fired steam electric generating units, ≥10 to <25 MW		BACT (AIP)	4/18/2007	0.075 lb/MMBtu *(58 ppm @ 3% O_2)* NH_3 slip: 13 ppm @ 3% O_2	0.17 lb/MMBtu *(220 ppm @ 3% O_2)*	0.01 lb/MMBtu *(22 ppm @ 3% O_2)*	0.025 lb/MMBtu *(14 ppm @ 3% O_2)*	Filterable: 0.012 lb/MMBtu *(0.006 gr/scf @ 12% CO_2)*
				BACT (tech. feasible)		0.015 lb/MMBtu *(12 ppm @ 3% O_2)* NH_3 slip: 2 ppm @ 3% O_2	0.01 lb/MMBtu *(13 ppm @ 3% O_2)*	0.01 lb/MMBtu *(22 ppm @ 3% O_2)*	0.02 lb/MMBtu *(11 ppm @ 3% O_2)*	Filterable: 0.012 lb/MMBtu *(0.006 gr/scf @ 12% CO_2)*

Table D-6. Biomass-Fired Boiler

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
5	Massachusetts Department of Environmental Protection BACT Guidance for Biomass Projects	Solid biomass fuel-fired steam electric generating units, ≥25 MW		BACT (AIP)	4/18/2007	0.075 lb/MMBtu *(58 ppm @ 3% O_2)* NH_3 slip: 13 ppm @ 3% O_2	0.1 lb/MMBtu *(128 ppm @ 3% O_2)*	0.01 lb/MMBtu *(22 ppm @ 3% O_2)*	0.025 lb/MMBtu *(14 ppm @ 3% O_2)*	Filterable: 0.012 lb/MMBtu *(0.006 gr/scf @ 12% CO_2)*
				BACT (tech. feasible)		0.015 lb/MMBtu *(12 ppm @ 3% O_2)* NH_3 slip: 2 ppm @ 3% O_2	0.01 lb/MMBtu *(13 ppm @ 3% O_2)*	0.01 lb/MMBtu *(22 ppm @ 3% O_2)*	0.02 lb/MMBtu *(11 ppm @ 3% O_2)*	Filterable: 0.012 lb/MMBtu *(0.006 gr/scf @ 12% CO_2)*
6	Valley Bio-Energy; Modesto, CA	402 MMBtu/hr McBurney Corporation biomass-fired boiler with Detroit stoker vibrating grate feeder serving a steam turbine producing 33 MW (gross)	SNCR, SCR, dry powder scrubber w/ trona injection, multiclone, ESP	Authority to Construct		0.012 lb/MMBtu (24-hr block avg.)[7] *(9 ppm @ 3% O_2)* NH_3 slip: 50 ppmvd @ 3% O_2	0.046 lb/MMBtu (24-hr block avg.) *(59 ppm @ 3% O_2)*	0.005 lb/MMBtu *(11 ppm @ 3% O_2)*	0.012 lb/MMBtu (1-hr avg.) *(7 ppm @ 3% O_2)*	0.024 lb/MMBtu *(0.011 gr/scf @ 12% CO_2)*

[7] This limit is subject to a 12-month evaluation period to assess the operational variability and optimum control effectiveness of the emission control system to meet the target emission limit. In no event shall emissions exceed 0.065 lb/MMBtu (3-hr rolling avg.), except during startup and shutdown.

Table D-6. Biomass-Fired Boiler

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit NOx	CO	VOC	SO_2	PM10
7	SJVAPCD BACT analysis for San Joaquin Solar 1 & 2	(4) 425 MMBtu/hr Energy Products of Idaho (EPI) fluidized bubbling bed boiler with (1) 15 MMBtu/hr and (3) 50 MMBtu/hr natural gas-fired startup burners serving two steam turbines producing 53.4 MW each	RSCR or equal, limestone injection, baghouse or ESP, natural gas auxiliary fuel	BACT (AIP)	10/8/2009	0.075 lb/MMBtu *(58 ppm @ 3% O_2)*	0.1 lb/MMBtu *(128 ppm @ 3% O_2)*	0.01 lb/MMBtu *(22 ppm @ 3% O_2)*	0.025 lb/MMBtu *(14 ppm @ 3% O_2)*	0.045 lb/MMBtu *(0.002 gr/scf @ 12% CO_2)*
			Option 1: SNCR + SCR + wet scrubber or equal, limestone injection, baghouse + multiclones+ wet scrubber or equal, natural gas auxiliary fuel Option 2: SCR or equal, limestone injection, baghouse + multiclones+ wet scrubber or equal, natural gas auxiliary fuel	BACT (tech. feasible)		Option 1: 0.012 lb/MMBtu *(9 ppm @ 3% O_2)* Option 2: 0.065 lb/MMBtu *(50 ppm @ 3% O_2)*	0.046 lb/MMBtu *(59 ppm @ 3% O_2)*	0.005 lb/MMBtu *(11 ppm @ 3% O_2)*	0.012 lb/MMBtu *(7 ppm @ 3% O_2)*	0.024 lb/MMBtu *(0.011 gr/scf @ 12% CO_2)*
8	Wheelabrator; Delano, CA (changed name to AES Delano)	400 MMBtu/hr circulating fluidized bed boiler with steam turbine producing 31 MW	SNCR, limestone injection, sodium bicarbonate injection, multiclone and baghouse	Authority to Construct	1998	0.1 lb/MMBtu *(78 ppm @ 3% O_2)*	181 ppmv @ 3% O_2 *(0.14 lb/MMBtu)*	0.02 lb/MMBtu *(50 ppm @ 3% O_2)*	23 ppm @ 3% O_2 *(0.041 lb/MMBtu)*	0.01 gr/scf @ 12% CO_2 *(0.022 lb/MMBtu)*

Table D-6. Biomass-Fired Boiler										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
9	Thermal Energy Development Corporation, Ltd.; Tracy, CA	259 MMBtu/hr boiler (powers a 20.5 MW steam turbine electric generator)	Lime/ limestone injection, ammonia injection, ESP, SNCR	Permit	7/31/2005	0.105 lb/MMBtu *(82 ppm @ 3% O_2)* NH_3 slip: 100 ppm @ 3% O_2	0.21 lb/MMBtu *(270 ppm @ 3% O_2)*	0.049 lb/MMBtu *(110 ppm @ 3% O_2)*	0.024 lb/MMBtu *(13 ppm @ 3% O_2)*	0.034 lb/MMBtu *(0.016 gr/scf @ 12% CO_2)*
10	AES Unit 2; Delano, CA	400 MMBtu/hr bubbling fluidized bed boiler with (2) steam turbines producing 32 MW total	SNCR, limestone and sand injection, baghouse	Source test	6/12 to 13/2007	0.08 lb/MMBtu; 63 ppmvd @ 3% O_2	0.05 lb/MMBtu; 60 ppmvd @ 3% O_2	<0.0005 lb/MMBtu as methane	0.0001 lb/MMBtu as SO_2; 0.07 ppmvd @ 3% O_2	0.002 gr/dscf @ 12% CO_2 (total); (*0.004 lb/MMBtu*)
11	Rio Bravo; Fresno, CA	352 MMBtu/hr circulating fluidized bed boiler with steam turbine producing 24.3 MW	SNCR, ESP	Source test	11/11/2009	0.068 lb/MMBtu; 52 ppmvd @ 3% O_2 NH_3: 11.7 ppm @ 3% O_2	0.0004 lb/MMBtu; 0.47 ppmvd @ 3% O_2	0.75 lb/hr as methane; 4.1 ppm @ 3% O_2	0.0003 lb/MMBtu; 0.15 ppmvd @ 3% O_2	0.002 gr/dscf @ 12% CO_2 (filterable); 1.6 lb/hr (filterable); 7.7 lb/hr (condensable)
12	Pacific Industries; Lincoln, CA	289.3 MMBtu/hr fixed grate boiler with steam turbine producing 20 MW	SNCR, multiclone, ESP	Source test	2/9/2006	54 ppmvd @ 12% CO_2	N/A	N/A	N/A	0.0005 gr/dscf @ 12% CO_2 (total)
13	Madera Power; Madera, CA	460 MMBtu/hr fluidized bed boiler with steam turbine producing 28.5 MW	SNCR	Source test	8/25/2004	0.09 lb/MMBtu; 69 ppm @ 3% O_2	N/A	N/A	N/A	0.006 gr/dscf @ 12% CO_2 (total)

Table D-6. Biomass-Fired Boiler

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
14	Colmac Energy Inc.; Mecca, CA (Cabazon Reservation)	Boilers 1 and 2 – (2) 300 MMBtu/hr circulating fluidized bed boilers producing 47 MW total[8]	Thermal de-NOx system, cyclone / baghouse, limestone injection	Permit	8/2/2000	30.0 lbs/hr per boiler; 94 ppmvd @ 3% O_2 (3-hr avg.); 648 lbs/day per boiler; 0.30 lb/MMBtu (30-day rolling avg.)	45.0 lbs/hr per boiler; 231 ppmvd @ 3% O_2 (3-hr avg.)	10.0 lbs/hr per boiler	12.0 lbs/hr per boiler; 27 ppmvd @ 3% O_2 (3-hr avg.); 70 tpy daily rolling avg.	7.5 lbs/hr per boiler; 0.010 gr/dscf @ 12% CO_2; 0.10 lb/MMBtu

Table D-7. Sewage Digester and Landfill Gas-Fired Fuel Cell

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	ARB Distributed Generation Certification Regulation	DG unit subject to regulation and fueled by digester gas, landfill gas, or oil-field waste gas	Not specified	Regulation (effective date 9/7/2007)	On or after 1/1/2008 On or after 1/1/2013	0.5 lb/MWh 0.07 lb/MWh	6.0 lb/MWh 0.10 lb/MWh	1.0 lb/MWh 0.02 lb/MWh		
2	El Estero Wastewater Treatment Plant; El Estero, CA	(2) Fuel Cell Energy Model DFC 300A fuel cells	Digester gas cleanup system to remove excess sulfur compounds, moisture, particulates, H_2S, halogenated compounds, and silohexanes (total sulfur content ≤12 ppmv)	Permit		0.07 lb/MWh; 0.018 lb/hr	0.10 lb/MWh; 0.025 lb/hr	0.02 lb/MWh; 0.005 lb/hr	0.007 lb/hr	0.026 lb/hr

8 Boiler may be fired on natural gas and petroleum coke in addition to biomass (i.e., wood). Permit limits listed reflect biomass combustion.

Table D-7. Sewage Digester and Landfill Gas-Fired Fuel Cell										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
3	New York Power Authority/Red Hook Water Pollution Control Plant; Red Hook, NY	United Technologies Corp. PC25C phosphoric acid fuel cell producing 200 kW		Source test	5/19 to 6/19/2004	0.013 lb/MWh; 0.43 ppm @ 15% O_2	0.029 lb/MWh; 1.64 ppm @ 15% O_2	0.78 lb/MWh; 120 ppm @ 15% O_2		
4	Orange County Sanitation District; Fountain Valley, CA	Fuel Cell Energy Model DFC300 fuel cell		Permit (Manufacturer emission factor data)	11/12/2008	0.01 lb/MWh; 0.0035 lb/hr; 0.08 lb/day	0.1 lb/MWh; 0.035 lb/hr; 0.84 lb/day	0.01 lb/MWh; 0.003 lb/hr; 0.07 lb/day	0.0001 lb/MWh; 0.00003 lb/hr; 0 lb/day	0.00002 lb/MWh; 0.000007 lb/hr; 0 lb/day
5	Palmdale Water Reclamation Plant; Palmdale, CA	Fuel Cell Energy Model DFC300 fuel cell producing 251 kW		Source test	1/19/2005	0.0017 lb/MWh; 0.05 ppm @ 15% O_2; 0.1 ppm @ 3% O_2	0.025 lb/MWh; 1.2 ppm @ 15% O_2; 3.7 ppm @ 3% O_2	0.016 lb/MWh (as CH_4); 0.30 ppm @ 3% O_2 (as hexane)		
6	Penrose Landfill; Los Angeles, CA	International Fuel Cells PC25 phosphoric acid fuel cell producing 200 kW		Source test	2/17/1995	0.0053 lb/MWh; 0.12 ppmvd @ 15% O_2	0.021 lb/MWh; 0.77 ppmvd @ 15% O_2		<0.014 lb/MWh; <0.23 ppmvd @ 15% O_2	

Table D-8. Pumps and Compressor Seals

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit: NOx	CO	VOC	SO_2	PM10
1	BAAQMD BACT Guideline 137.1	Pumps	Double mechanical seals w/ barrier fluid and BAAQMD approved quarterly I&M Program	BACT (AIP)	1/18/2006			500 ppm expressed as methane measured using EPA Reference Method 21		
			Double mechanical seals w/ barrier fluid; magnetically coupled pumps; canned pumps; magnetic fluid sealing technology or gas seal system vented to thermal oxidizer or other BAAQMD approved control device; all w/ BAAQMD approved quarterly I&M Program	BACT (tech. feasible)				100 ppm expressed as methane using EPA Reference Method 21		

Table D-8. Pumps and Compressor Seals

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit: NOx	CO	VOC	SO_2	PM10
2	BAAQMD BACT Guideline 48B.1	Compressors	Double mechanical seals w/ barrier fluid and BAAQMD approved quarterly I&M Program	BACT (AIP)	1/18/2006			500 ppm expressed as methane measured using EPA Reference Method 21		
			Double mechanical seals w/ barrier fluid; or gas seal system vented to thermal oxidizer or other BAAQMD approved control device; all w/ BAAQMD approved quarterly I&M Program	BACT (tech. feasible)				100 ppm expressed as methane using EPA Reference Method 21		

Table D-8. Pumps and Compressor Seals

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
3	SJVAPCD Guideline 4.12.1 – Chemical Plants – Pumps and Compressor Seals[9]	Chemical plants pump and compressor seals	I&M Program	BACT (AIP)	11/27/2006			Leak defined as a reading of methane in excess of 500 ppmv above background when measure per EPA Method 21 and an Inspection and Maintenance Program pursuant to SJVAPCD Rule 4455		
4	BAAQMD Regulation 8 Rule 18 Equipment Leaks	Pumps and compressors		District approved rule	Last amended 9/15/2004			500 ppm maximum leak rate using a hydrocarbon detector that meets the specifications and performance criteria of and has been calibrated using EPA Reference Method 21		

[9] Based on Lone Star Gas Liquids Processing, Inc., Bakersfield, CA.

Table D-9. Valves, Flanges, and Other Types of Connectors

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	Pacific Ethanol; Madera, CA	Piping, valves and flanges	I&M program	Authority to Construct	2005			100 ppmvd as methane maximum leak valves and flanges; 500 ppmvd as methane pumps and compressor seals		
2	SJVAPCD Guideline 4.12.1 – Chemical Plants - Valves and Connectors	Chemical plants valves and connectors	I&M Program	BACT (AIP)	11/26/2006			Leak defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21 and Maintenance Program pursuant to SJVAPCD Rule 4455		
3	BAAQMD BACT Guideline 78.1	Flanges	Graphitic gaskets and BAAQMD approved I&M Program	BACT (AIP)	1/18/2006			100 ppm expressed as methane measured using EPA Reference Method 21		

Table D-9. Valves, Flanges, and Other Types of Connectors

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
4	BAAQMD Regulation 8 Rule 18 Equipment Leaks	Valves and connections		District approved rule	Last amended 9/15/2004			100 ppm maximum leak rate from valves and connections using a hydrocarbon detector that meets the specifications and performance criteria of and has been calibrated using EPA Reference Method 21		

Table D-10. Wet Cooling Tower

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	SJVAPCD Guideline 8.3.10	Cooling Tower – Induced Draft, Evaporative Cooling		BACT (tech. feasible)	6/19/2000					Cellular type drift eliminator
2	Los Esteros Critical Energy Facility Phase 2; San Jose, CA	Cooling tower, six-cell		Final Commission Decision	October 2006					High efficiency mist eliminator with maximum guaranteed drift rate of 0.0005%
3	Walnut Creek Energy, LLC; City of Industry, CA	Cooling tower, five-cell		Authority to Construct	10/27/2006					Maximum 0.0005% drift loss

Table D-10. Wet Cooling Tower

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
4	Homeland Energy Solutions, LLC; Chickasaw County, IA	Cooling tower		BACT-PSD	7/21/2008					Drift eliminator/ demister with 0.0005% drift loss
5	Archer Daniels Midland (ADM) Corn Processing; Linn County, IA	Cooling tower		BACT-PSD	10/9/2007					Drift eliminator with 0.0005% drift loss

Table D-11. Landfill Gas-Fired Flare

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	SJVAPCD Guideline 1.4.3	Landfill gas-fired flare	Enclosed flare	BACT (tech. feasible)	1/8/2001	0.05 lb/MMBtu *(40 ppm @ 3% O_2)*	N/A	N/A	Wet scrubber w/ 98% control efficiency	Steam injection
2	SJVAPCD Guideline 1.4.3	Landfill gas-fired flare	Enclosed flare	BACT (AIP)	1/8/2001	N/A	N/A	98% control efficiency; 20 ppmv @ 3% O_2	N/A	N/A
3	SCAQMD Guidelines for Non-Major Facilities	Landfill gas-fired flare		BACT	2000	0.06 lb/MMBtu *(50 ppm @ 3% O_2)*	N/A	N/A	N/A	Knockout vessel
4	Altamont Landfill; Livermore, CA	Landfill gas-fired flare		Permit	2005	0.06 lb/MMBtu *(50 ppm @ 3% O_2)*	0.30 lb/MMBtu *(400 ppm @ 3% O_2)*	N/A	N/A	N/A
5	SCAQMD BACT Guidelines Part B, Section II (Waste Management of New Hampshire; Rochester, NH)	Flare, landfill gas from non-hazardous waste landfill (115.5 MMBtu/hr)	Enclosed flare	BACT	4/18/2006	0.025 lb/MMBtu	0.06 lb/MMBtu	98% destruction efficiency or 20 ppm @ 3% O_2 as hexane	1.66 lb/hr; 0.014 lb/MMBtu	2.32 lb/hr; 0.02 lb/MMBtu

Table D-11. Landfill Gas-Fired Flare

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
6	SCAQMD BACT Guidelines Part B, Section II (NEO Tajiguas Energy LLC; Goleta, CA)	Flare, landfill gas from non-hazardous waste landfill (63.68 MMBtu/hr)	Enclosed flare	BACT	9/8/2004	35 ppmvd @ 3% O2; 0.048 lb/MMBtu	N/A	1.25-second residence time and 1500 °F minimum temperature and 15 ppmvd @ 3% O2 as hexane; 0.038 lb/MMBtu	N/A	N/A

Table D-12. Manure Digester Gas-Fired Flare

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	SJVAPCD Guideline 1.4.4	Digester gas-fired flare	Ultra low NOx flare	BACT (tech. feasible)	5/16/2006	≤0.03 lb/MMBtu *(25 ppm @ 3% O_2)*	N/A	N/A	1. Dry absorption of H_2S from the fuel gas 2. Wet absorption of H_2S from the fuel gas 3. Influent fuel H_2S reduction by addition of chemicals to the digester gas sludge 4. Water scrubbing of H_2S from the fuel gas	N/A
2	SJVAPCD Guideline 1.4.4	Digester gas-fired flare	Enclosed flare	BACT (AIP)	5/16/2006	≤0.06 lb/MMBtu *(50 ppm @ 3% O_2)*	Operate per manufacturer specifications to minimize CO	≤0.068 lb/MMBtu *(161 ppm @ 3% O_2)*	LPG or natural gas-fired pilot	Smokeless combustion and LPG or natural gas-fired pilot
3	SJVAPCD Guideline 1.4.6 (Biorecycling Solutions)	Biogas-fired flare, limited use		BACT (tech. feasible)	1/20/1998	0.06 lb/MMBtu *(50 ppm @ 3% O_2)*	N/A	0.03 lb/MMBtu *(71 ppm @ 3% O_2)*	N/A	N/A
4	SJVAPCD Guideline 2.2.3	Cheese wastewater-fired flare	Enclosed flare, ultra low NOx burner, low NOx burner	BACT (tech. feasible)	6/28/2004	≤0.03 lb/MMBtu *(25 ppm @ 3% O_2)*	N/A	N/A	99% H_2S removal (dry or wet scrubber)	Smokeless combustion and LPG or natural gas-fired pilot

Table D-13. Flare (Ethanol Production)										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	ADM Corn Processing; Cedar Rapids, Iowa	Loadout flare		Permit	7/17/2008	0.15 lb/MMBtu	N/A	95% control; 4.82 lb/hr; 12.2 tpy	0.02 lb/hr; 0.09 tpy	0.1gr/dscf
2	Center Ethanol Company, LLC; East St. Louis, IL	Loadout flare		Permit		0.23 tons/month; 2.31 tpy	0.39 tons/month; 3.87 tpy	1.55 tons/month; 2.31 tpy	N/A	N/A
3	Pacific Ethanol; Madera, CA	Loadout flare	Low NOx burner	Permit	7/8/2008	0.05 lb/MMBtu	0.84 lb/MMBtu	0.327 lb/MMBtu	0.00285 lb/MMBtu	0.0076 lb/MMBtu
4	Pacific Ethanol; Oregon	Loadout flare		Permit		1.62 tpy	2.71 tpy	7.47 tpy	N/A	N/A
5	Phoenix Bio Industries; Goshen, CA	Loadout flare	Air assist	Permit	9/20/2004	0.068 lb/MMBtu	0.37 lb/MMBtu	0.063 lb/MMBtu	0.00285 lb/MMBtu	0.008 lb/MMBtu
6	Pixley Ethanol; Pixley, CA	Loadout flare	Enclosed	Permit	7/20/2005	0.068 lb/MMBtu	0.37 lb/MMBtu	0.063 lb/MMBtu	0.00286 lb/MMBtu	0.026 lb/MMBtu

Table D-14. Storage Tank (Fixed Roof)

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	American Biodiesel; Stockton, CA	Methanol storage tank	Vapor recovery routed to distillation column and two-stage vapor condenser	Authority to Construct	6/4/2007			99.5% control		
2	SJVAPCD Guideline 7.3.1 - Petroleum and Petrochemical Production - Fixed Roof Organic Liquid Storage or Processing Tank, <5,000 bbl tank capacity[10]	Methanol storage tank	Waste gas incinerated in steam generator, heater treater, or other fired equipment and inspection and maintenance program: transfer of noncondensable vapors to gas pipeline; or equal	BACT (tech. feasible)	10/1/2002			99% control		
3	BAAQMD BACT Guideline 167.3.1	≥20,000 gallon storage tank – fixed roof, organic liquids	Thermal incinerator; or carbon adsorber; or refrigerated condenser; or BAAQMD approved equivalent	BACT (AIP)	3/3/1995			Vapor recovery system w/ an overall system efficiency ≥98%		
4	NSPS 40 CFR Part 60 Subpart Kb	Methanol storage tank	Closed vent system and 95% VOC control efficiency					95% control		

[10] Based on District facility S-1339 heavy oil western stationary source.

Table D-15. Storage Tank (Floating Roof)										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	BAAQMD BACT Guideline 167.1.1 and Guideline 167.4.1	Storage tank – external floating roof, organic liquids; storage tank – internal floating roof, organic liquids	BAAQMD approved roof and seal design	BACT (AIP)	3/3/1995			BAAQMD approved roof w/ liquid mounted primary seal and zero gap secondary seal, all meeting design criteria of Reg. 8, Rule 5; no ungasketed roof penetrations, no slotted pipe guide pole unless equipped w/ float and wiper seals, and no adjustable roof legs unless fitted w/ vapor seal boots or equivalent		
			Thermal incinerator; or carbon adsorber; or refrigerated condenser; or BAAQMD approved equivalent	BACT (tech. feasible)				Vapor recovery system w/ an overall system efficiency ≥98%		

Table D-15. Storage Tank (Floating Roof)

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
2	Calgren Renewable Fuels LLC; Pixley, CA	Ethanol tank (from 67,700 to 1,000,000 gallons)	Tank equipped with double seals, one mounted on top of the other (meeting SJVAPCD Rule 4623)	Authority to Construct	8/24/2005			95% control		

Table D-16. Dryer

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	SJVAPCD Guideline 4.12.6 A	Distillers Dried Grains with Solubles (DDGS) Dryer	Low NOx burners, cyclone, thermal or catalytic incinerator	BACT (AIP)	5/25/2004	33 ppmv @ 3% O_2; 0.04 lb/MMBtu	N/A	VOC capture and control with thermal or catalytic incineration (98% control) or equivalent	Natural gas fuel	High efficiency (1D-3D) cyclones and thermal incinerator in series (98.5% control) or equivalent
2	SJVAPCD Guideline 4.12.6 A	Distillers Dried Grains with Solubles (DDGS) Dryer	Ultra low NOx burners, wet scrubber	BACT (tech. feasible)	5/25/2004	15 ppmv @ 3% O_2; 0.018 lb/MMBtu	N/A	N/A	Wet scrubber (95% control)	N/A
3	Golden Grain Energy; Cerro Gordo County, IA	Distillers Dried Grains with Solubles (DDGS) Dryer (42 MMBtu/hr)	Low NOx burners, FGR, thermal oxidizer	BACT-PSD	4/19/2006	8.36 lb/hr; 0.04 lb/MMBtu (30-day avg.)	25.5 lb/hr; 0.61 lb/MMBtu	98% control; 2.75 lb/hr (*0.065 lb/MMBtu)*	N/A	4.5 lb/hr; 0.03 lb/MMBtu (3-hr avg.)
4	Abengoa Bioenergy of Illinois, LLC; Madison, IL	Indirect Feed Dryer (76.7 MMBtu/hr)	Integral cyclone and burner/kiln	Permit	7/13/2007	6.52 lb/hr (*0.085 lb/MMBtu)*	7.97 lb/hr (*0.104 lb/MMBtu)*	1.96 lb/hr (*0.026 lb/MMBtu)*	0.04 lb/hr (*0.0005 lb/MMBtu)*	3.71 lb/hr (*0.048 lb/MMBtu)*

Table D-16. Dryer										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
5	Bluefire Ethanol; Lancaster, CA	Biomass dryer (shared stack with CFB biomass boiler[11])	Baghouse, SOx scrubber with limestone, and SNCR with aqueous NH_3 injection	Permit	12/16/2008	144 lb/day; 0.075 lb/MMBtu (Combined boiler and dryer daily emission limit; lb/MMBtu limit from district engineering evaluation)	134.4 lb/day; 0.07 lb/MMBtu (Combined boiler and dryer daily emission limit; lb/MMBtu limit from district engineering evaluation)	103.5 lb/day; 0.013 lb/MMBtu (Combined boiler and dryer daily emission limit; lb/MMBtu limit from district engineering evaluation)	132.5 lb/day; 0.069 lb/MMBtu (Combined boiler and dryer daily emission limit; lb/MMBtu limit from district engineering evaluation)	42.3 lb/day; 0.022 lb/MMBtu (Combined boiler and dryer daily emission limit; lb/MMBtu limit from district engineering evaluation)
6	American Biodiesel; Stockton, CA	Steam-heated feedstock Dryer (completely enclosed)	Vapor recovery system	Permit	6/4/2007			99.5 % control		

[11] Dual fuel firing occurs at startup using 25 MMBtu/hr natural gas-fired burner for overbed air and 15 MMBtu/hr natural gas-fired burner for underbed air.

Table D-17. Pyrolyzer

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	International Environmental Solutions Corp.; Romoland, CA	Non-hazardous feedstocks pyrolysis system, including pyrolytic thermal converter (retort), indirectly heated with (4) Eclipse Therm Jet low NOx burners, Model TJ150, natural gas-fired, 1.5 MMBtu/hr each, with a combustion air blower and hydraulically driven variable speed helical screw	Low-NOx burners, pyrolytic converter vented to control system consisting of: multiclone, thermal oxidizer, waste heat boilers, activated carbon injection system, baghouse, wet scrubber, exhaust stack with in-stack mounted carbon filter	Permit to Construct and Operate Experimental Research Project[12] Note: This was an experimental research demonstration project and is no longer operating, nor is the permit valid anymore.	3/7/2006	Pyrolysis gas burner stack: 6 lbs/day Scrubber stack: 34 lbs/day (NH_3: 2.5 lbs/day)	Pyrolysis gas burner stack: 5 lbs/day Scrubber stack: 9 lbs/day	Pyrolysis gas burner stack: 1 lb/day Scrubber stack: 11 lbs/day	Pyrolysis gas burner stack: 0.1 lb/day Scrubber stack: 1 lb/day	Pyrolysis gas burner stack: 1 lb/day Scrubber stack: 1 lb/day

Table D-18. Liquid Fuel Loading Operations

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	Abengoa Bioenergy of Illinois, LLC; Madison, IL	Ethanol Loadout Racks		Permit	7/13/2007			1.45 tons/month; 14.45 tpy		
2	Bluefire Ethanol; Lancaster, CA	Ethanol Loadout	Vapor recovery and control system, beer vent scrubber	Permit	12/16/2008			50 ppmv; 2.8 lb/day		

[12] Permit conditions were crafted to limit operating hours and emissions to just below the levels that would trigger federal requirements for small municipal solid waste combustors. According to SCAQMD staff, is it likely that more efficient air pollution control would have been required if the company requested either more operating time and/or higher throughput.

Table D-18. Liquid Fuel Loading Operations

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
3	Lomita Rail Terminal, LLC; Carson, CA	Ethanol Unloading	Carbon adsorber	Permit	12/2/2003			Leak defined as a reading of methane greater than 500 ppm but less than 1000 ppm above background when measured per EPA Method 21. Leak greater than 1000 ppm above background shall be repaired according to SCAQMD Rule 1173		
4	Verenium Biofuels; Jennings, Jefferson Davis Parish, LA	Ethanol loadout	Carbon adsorption canister	Permit	5/13/2008			98% control		

Table D-18. Liquid Fuel Loading Operations										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
5	West Colton Rail Terminal LLC; Rialto, CA	Railcar unloading/truck loading, ethanol	Carbon adsorber, vapor balance system	Permit	11/10/2009			0.08 lbs/1000 gallons loaded (SCAQMD Rule 462 – Organic Liquid Loading) and leak defined as a reading of methane greater than 500 ppm but less than 1000 ppm above background when measured per EPA Method 21. Leak greater than 1000 ppm above background shall be repaired according to SCAQMD Rule 1173		

Table D-19. Compressed Gas Dispensing Operations

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	Los Angeles County Sanitation District, aka Puente Hills Landfill; Whittier, CA	Landfill gas treating and dispensing system (250 scfm collected and treated to produce CNG for pick-up trucks)	All vent gases and excess processed gas shall be directed to combustion or processing facility that can adequately process the gas and has been issued a valid District permit	Permit	2/12/1997	No direct emissions – operation of equipment shall not result in release of any gas or condensate into the atmosphere				
2	Sonoma County Central Landfill; Petaluma, CA	Landfill gas compression plant, pilot scale (100 scfm collected and treated to produce CNG for vehicles)	Closed loop system w/ no vents or exhaust stacks; all waste gas transferred to treatment systems or flared	Permit	4/18/2008	No direct emissions – closed loop system				

Table D-20. Liquid Fuel Transfer and Dispensing Operations

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	SCAQMD Rule 461 Gasoline Transfer and Dispensing	Fuel[13] transfer into stationary storage tanks and mobile fuelers	Phase I vapor recovery system[14]	Rule	3/7/2008					

13 Applies to biofuel blends that meet the definition of "gasoline" as defined in Rule 461.

14 Rule 461 exempts the dispensing of E-85 into a mobile fueler of vehicle fuel tank from Phase II vapor recovery requirements until April 1, 2012.

Table D-21. Sewage Digester and Landfill Gas-Fired Microturbine

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	Capstone Turbine Corporation; Chatsworth, CA	Capstone CR65 digester gas-fueled microturbine		Source test (for ARB DG Certification Program)	6/8/2007	0.15 lb/MWh; 8.73 ppmvd @ 3% O_2; *3 ppmvd @ 15% O_2*	4.52 lb/MWh; 385.92 ppmvd @ 3% O_2; 127 *ppmvd @ 15% O_2*	0.23 lb/MWh; 42.06 ppmvd @ 3% O_2 as CH_4 (total non-methane, non-ethane organic compounds); 14 *ppmvd @ 15% O_2*	8.64 ppmvd @ 3% O_2; *3 ppmvd @ 15% O_2*	
2	Capstone Turbine Corporation; Chatsworth, CA	Capstone CR65 landfill gas-fueled microturbine		Source test (for ARB DG Certification Program)	8/8/2007	0.10 lb/MWh; 4.56 ppmvd @ 3% O_2; 2 *ppmvd @ 15% O_2*	0.61 lb/MWh; 31.48 ppmvd @ 3% O_2; 10 *ppmvd @ 15% O_2*	0.13 lb/MWh; 18.46 ppmvd @ 3% O_2 as CH_4 (total non-methane, non-ethane organic compounds); 6 *ppmvd @ 15% O_2*	32.11 ppmvd @ 3% O_2; 11 *ppmvd @ 15% O_2*	
3	Ingersoll Rand Energy Systems; Portsmouth, NH	Ingersoll Rand 250 kW 250ST digester gas-fueled microturbine		Source test (for ARB DG Certification Program)	1/16/2008	0.114 lb/MWh; 2.2 ppmvd @ 15% O_2	0.029 lb/MWh; 0.9 ppmvd @ 15% O_2	0.13 lb/MWh; 1.3 ppmvd @ 15% O_2 (as hexane)	0.018 lb/hr	
4	Ingersoll Rand Energy Systems; Portsmouth, NH	Ingersoll Rand 250 kW 250SW landfill gas-fueled microturbine		Source test (for ARB DG Certification Program)	1/9/2008	0.36 lb/MWh; 6.5 ppmvd @ 15% O_2	0.041 lb/MWh; 1.2 ppmvd @ 15% O_2	0.10 lb/MWh; 0.92 ppmvd @ 15% O_2 (as hexane)	0.017 lb/hr	

Table D-22. Landfill Gas-Fired Reciprocating Internal Combustion Engine

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	SCAQMD Rule 1110.2 Emissions from Gaseous- and Liquid-Fueled Engines	Stationary and portable engines >50 bhp, landfill and digester gas-fired		Rule	2/1/2008	<500 bhp: 45 x ECF[15] ppmvd @ 15% O_2 ≥500 bhp: 36 x ECF ppmvd @ 15% O_2 --- On and after 7/1/2012: 11 ppmvd @ 15% O_2	2,000 ppmvd @ 15% O_2 --- On and after 7/1/2012: 250 ppmvd @ 15% O_2	40 ppmvd @ 15% O_2 --- On and after 7/1/2012: 30 ppmvd @ 15% O_2	N/A	N/A
2	8309 Tujunga Ave. Corp. (Austin Rd. Landfill); Stockton, CA	1,100 hp landfill gas-fired IC engine		Source test	12/13/2006	0.3 g/bhp-hr; 20 ppmv @ 15% O_2	3.0 g/bhp-hr; 291 ppmv @ 15% O_2	0.2 g/bhp-hr; 38 ppmv @ 15% O_2	Non-detected	0.01 g/bhp-hr; 0.001 gr/dscf
3	ARB DG Guidance[16]	Waste gas-fired reciprocating engine used in electrical generation (that are required to obtain a district permit)	Lean-burn technology	BACT	2002	0.6 g/bhp-hr; 50 ppmvd @ 15% O_2; 1.9 lb/MWh	2.5 g/bhp-hr; 300 ppmvd @ 15% O_2; 7.8 lb/MWh	0.6 g/bhp-hr; 130 ppmvd @ 15% O_2; 1.9 lb/MWh	N/A	N/A
4	Apollo Energy III (Bowerman Landfill); Irvine, CA	1,468 bhp landfill gas IC engine, producing 1.06 MW	Lean burn technology, turbocharged, aftercooled	Permit		0.5 g/bhp-hr	0.3 g/bhp-hr	0.2 g/bhp-hr (NMHC)	N/A	N/A
5	Apollo Energy III (Bowerman Landfill); Irvine, CA	1,468 bhp landfill gas IC engine, producing 1.06 MW	Lean burn technology, turbocharged, aftercooled	Source test	7/05 to 06/2007	0.4 g/bhp-hr; 32 ppm @ 15% O_2	0.2 g/bhp-hr; 19 ppm @ 15% O_2	0.01 g/bhp-hr (CH_4) TGNMO	N/A	0.004 gr/dscf @ 12% CO_2

[15] ECF is the efficiency correction factor. ECF = 1.0 unless the engine operator has measured the engine's net specific energy consumption, in compliance with ASME Performance Test Code PTC 17-1973, at the average load of the engine (see rule for details).

[16] Emission levels based on permit and source test data from the following facilities: County of Sacramento (Kiefer Landfill), Energy Developments (Azusa Landfill), Minnesota Methane (Tajiguas Landfill), Riverside County Waste Management (Badlands), Minnesota Methane (Lopez Landfill), Minnesota Methane (Corona), Ogden Power Pacific (Stockton), Orange County Sanitation District (Huntington Beach).

Table D-22. Landfill Gas-Fired Reciprocating Internal Combustion Engine										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
6	Kiefer Landfill; Sacramento, CA – 5 units	4,230 bhp landfill gas-fired IC engine, producing 3.05 MW each	Lean burn technology, turbocharged	Permit		0.4 g/bhp-hr OR 30.0 ppmv @ 15% O_2 (both 3-hr avg)	2.6 g/bhp-hr OR 366 ppmv @ 15% O_2 (both 3-hr avg)	0.1 g/bhp-hr	0.3 g/bhp-hr	0.1 g/bhp-hr
7	Kiefer Landfill; Sacramento, CA – 5 units	4,230 bhp landfill gas-fired IC engine, producing 3.05 MW each	Lean burn technology, turbocharged	Source test Unit 1	11/10/2005	0.3 g/bhp-hr; 24 ppm @ 15% O_2	1.9 g/bhp-hr; 253 ppm @ 15% O_2	Failed	Fuel: 0.6 gr/100 scf	0.06 g/bhp-hr
8	Kiefer Landfill; Sacramento, CA – 5 units	4,230 bhp landfill gas-fired IC engine, producing 3.05 MW each	Lean burn technology, turbocharged	Source test Unit 1	10/25/2006	0.3 g/bhp-hr; 2 ppm @ 15% O_2	2.2 g/bhp-hr; 241 ppm @ 15% O_2	N/A	Fuel: 29 ppmv	Failed
9	Kiefer Landfill; Sacramento, CA – 5 units	4,230 bhp landfill gas-fired IC engine, producing 3.05 MW each	Lean burn technology, turbocharged	Source test Unit 1	1/31/2007	N/A	N/A	N/A	Fuel: 22 ppmv	0.04 g/bhp-hr
10	Kiefer Landfill; Sacramento, CA – 5 units	4,230 bhp landfill gas-fired IC engine, producing 3.05 MW each	Lean burn technology, turbocharged	Source test Unit 1	3/28/2007	0.3 g/bhp-hr; 23 ppm @ 15% O_2	2.0 g/bhp-hr; 241 ppm @ 15% O_2	0.06 g/bhp-hr; 2.3 ppmv @ 15% O_2 as hexane	Fuel: 22 ppmv	0.04 g/bhp-hr
11	Kiefer Landfill; Sacramento, CA – 5 units	4,230 bhp landfill gas-fired IC engine, producing 3.05 MW each	Lean burn technology, turbocharged	Source test Unit 2	11/09/2005	0.3 g/bhp-hr; 26 ppm @ 15% O_2	2.0 g/bhp-hr; 224 ppm @ 15% O_2	Failed	Fuel: 0.2 gr/100 scf	0.10 g/bhp-hr
12	Kiefer Landfill; Sacramento, CA – 5 units	4,230 bhp landfill gas-fired IC engine, producing 3.05 MW each	Lean burn technology, turbocharged	Source test Unit 2	10/26/2006	0.4 g/bhp-hr; 24 ppm @ 15% O_2	1.7 g/bhp-hr; 233 ppm @ 15% O_2	N/A	Fuel: 29 ppmv	0.07 g/bhp-hr
13	Kiefer Landfill; Sacramento, CA – 5 units	4,230 bhp landfill gas-fired IC engine, producing 3.05 MW each	Lean burn technology, turbocharged	Source test Unit 2	3/27/2007	0.3 g/bhp-hr; 25 ppm @ 15% O_2	1.9 g/bhp-hr; 245 ppm @ 15% O_2	0.05 g/bhp-hr; 2.2 ppmv @ 15% O_2 as hexane	Fuel: 22 ppmv	0.04 g/bhp-hr
14	Kiefer Landfill; Sacramento, CA – 5 units	4,230 bhp landfill gas-fired IC engine, producing 3.05 MW each	Lean burn technology, turbocharged	Source test Unit 3	11/08/2005	0.3 g/bhp-hr; 21 ppm @ 15% O_2	1.8 g/bhp-hr; 220 ppm @ 15% O_2	0.08 g/bhp-hr as CH_4	Fuel: 0.3 gr/100 scf	0.05 g/bhp-hr
15	Kiefer Landfill; Sacramento, CA – 5 units	4,230 bhp landfill gas-fired IC engine, producing 3.05 MW each	Lean burn technology, turbocharged	Source test Unit 3	1/30/2007	0.3 g/bhp-hr; 23 ppm @ 15% O_2	1.7 g/bhp-hr; 199 ppm @ 15% O_2	0.1 g/bhp-hr as CH_4	Fuel: 22 ppmv	0.05 g/bhp-hr

Table D-22. Landfill Gas-Fired Reciprocating Internal Combustion Engine										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
16	Kiefer Landfill; Sacramento, CA – 5 units	4,230 bhp landfill gas-fired IC engine, producing 3.05 MW each	Lean burn technology, turbocharged	Source test Unit 4	5/11/2006	0.3 g/bhp-hr; 21 ppm @ 15% O_2	1.6 g/bhp-hr; 209 ppm @ 15% O_2	0.05 g/bhp-hr as hexane	Fuel: 34 ppmv	0.08 g/bhp-hr
17	Kiefer Landfill; Sacramento, CA – 5 units	4,230 bhp landfill gas-fired IC engine, producing 3.05 MW each	Lean burn technology, turbocharged	Source test Unit 4	4/04/2007	0.3 g/bhp-hr; 26 ppm @ 15% O_2	2.4 g/bhp-hr; 304 ppm @ 15% O_2	0.10 g/bhp-hr; 4.0 ppmv as hexane	Fuel: 22 ppmv	0.09 g/bhp-hr
18	Kiefer Landfill; Sacramento, CA – 5 units	4,230 bhp landfill gas-fired IC engine, producing 3.05 MW each	Lean burn technology, turbocharged	Source test Unit 5	5/12/2006	0.3 g/bhp-hr; 22 ppm @ 15% O_2	1.7 g/bhp-hr; 205 ppm @ 15% O_2	0.06 g/bhp-hr as hexane	Fuel: 34 ppmv	0.08 g/bhp-hr; 0.009 gr/dscf
19	Kiefer Landfill; Sacramento, CA – 5 units	4,230 bhp landfill gas-fired IC engine, producing 3.05 MW each	Lean burn technology, turbocharged	Source test Unit 5	3/29 to 30/2007	0.4 g/bhp-hr; 27 ppm @ 15% O_2	2.0 g/bhp-hr; 253 ppm @ 15% O_2	0.07 g/bhp-hr; 2.9 ppmv as hexane	Fuel: 22 ppmv	0.08 g/bhp-hr; 0.009 gr/dscf
20	MM San Bernardino Energy, LLC (Milliken Landfill); Ontario, CA	1850 bhp (14.7 MMBtu/hr) Deutz Model TBG620V16K landfill gas-fired IC engine	Engine design, air/fuel ratio controller, turbocharger, intercooler	BACT (NOx, CO, VOC)	2/20/2003	0.6 g/bhp-hr	2.5 g/bhp-hr	0.8 g/bhp-hr	0.10 lb/hr; *0.02 g/bhp-hr; 0.007 lb/MMBtu*	0.20 lb/hr; *0.05 g/bhp-hr; 0.014 lb/MMBtu*
21	Minnesota Methane Tajiguas Corp.; Goleta, CA	4314 bhp Caterpillar Model 3616 landfill gas-fired engine driving a 3 MW generator with exhaust routed to afterburner/standby flare	Lean-burn technology w/ spark ignition controls, air/fuel ratio controls, intake air turbocharger and intercooler, fuel pretreatment to remove gas condensate and filter particles	BACT	1/9/1998	0.59 g/bhp-hr	N/A	0.24 g/bhp-hr	N/A	0.34 g/bhp-hr
22	Puente Hills Landfill; Whittier, CA – 3 units	4,261 bhp landfill gas-fired engine, with natural gas as secondary fuel	Lean burn technology, turbocharged, aftercooled, producing 3 MW	Permit		0.6 g/bhp-hr	2.5 g/bhp-hr	ROC: 0.8 g/bhp-hr; NMHC: 20 ppmv @ 3% O_2 OR 98% reduction	N/A	N/A

Table D-22. Landfill Gas-Fired Reciprocating Internal Combustion Engine

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
23	Puente Hills Landfill, Whittier, CA Unit 1	4,261 bhp landfill gas-fired IC engine, with natural gas as secondary fuel	Lean burn technology, turbocharged, aftercooled, producing 3 MW	Source test	7/11 to 14/2006	0.4 g/bhp-hr	1.7 g/bhp-hr	0.2 g/bhp-hr; 18.4 ppm @ 3% O_2 (as hexane)	N/A	N/A
24	Ridgewood Olinda Management, LLC; Brea, CA – 3 units	2,650 bhp landfill gas-fired IC engine, no auxiliary fuel, producing 1.875 MW each	Siloxane scrubber	Permit	11/17/2004	36 ppm @ 15% O_2; *0.7 g/bhp-hr*	2000 ppm @ 15% O_2; 22.7 g/bhp-hr	250 ppm as CH_4 @ 15% O_2	N/A	N/A
25	Ridgewood Olinda Management, LLC; Brea, CA Unit 1	2,650 bhp landfill gas-fired IC engine, no auxiliary fuel, producing 1.875 MW each	Siloxane scrubber	Source test[17]	6/13/2007	31 ppm @ 15% O_2; 0.5 g/bhp-hr	2 ppm @ 15% O_2; 0.0 g/bhp-hr	4 ppm @ 15% O_2 as CH_4, TGNMO; 0.02 g/bhp-hr	1.85 ppm	0.0006 gr/dscf @ 12% CO_2
26	Simi Valley Landfill; Simi Valley, CA – 2 units	1,877 bhp landfill gas-fired IC engine	Lean burn technology, turbocharged, aftercooled	Permit		35 ppmvd @ 15% O_2 OR 0.6 g/bhp-hr	280 ppmvd @ 15% O_2; *3.2 g/bhp-hr*	28 ppmvd @ 15% O_2; *1.0 g/bhp-hr*	0.02 lb/MMBtu	N/A
27	Waste Management; Livermore, CA	(2) 1,877 bhp Deutz IC engines fueled by landfill gas, LNG, or LNG Plant waste gas (Units S-23 and S-24)		Permit		0.6 g/bhp-Hr OR 36 ppmvd @ 15% O2	2.1 g/bhp-hr OR 207 ppmvd @ 15% O2	98% destruction efficiency by weight OR <120 ppmv @ 3% O2[18]	N/A	N/A
28	BAAQMD Guideline 96.2.2	IC engine – landfill gas fired <250 bhp output	Modified rich burn technology	BACT (AIP)	6/15/2006	2.5 g/bhp-hr	10.0 g/bhp-hr	1.5 g/bhp-hr	0.5 g/bhp-hr	N/A

[17] There are two test result tables for this test. The numbers differ between the tables. The data shown here came from the table with the higher reported emissions.
[18] Requirement from District Rule 8-34-301.4 (last amended June 15, 2005).

Table D-22. Landfill Gas-Fired Reciprocating Internal Combustion Engine

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
29	BAAQMD Guideline 96.2.2	IC engine – landfill gas fired >250 bhp output, low-NOx engine bias	Lean burn technology	BACT (AIP)	3/5/2009	0.5 g/bhp-hr	Initial standard: 2.5 g/bhp-hr Not to exceed standard: 3.9 g/bhp-hr CO emissions based on overhaul schedule	120 ppm @ 3% O2 (0.16 g/bhp-hr)	N/A	N/A
30	BAAQMD Guideline 96.2.2	IC engine – landfill gas fired >250 bhp output, low-CO engine bias	Lean burn technology	BACT (AIP)	3/5/2009	0.6 g/bhp-hr	Initial standard: 2.1 g/bhp-hr Not to exceed standard: 3.6 g/bhp-hr CO emissions based on overhaul schedule	120 ppm @ 3% O2 (0.16 g/bhp-hr)	N/A	N/A

Table D-23. Sewage Digester Gas-Fired Reciprocating Internal Combustion Engine										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	SCAQMD Rule 1110.2 Emissions from Gaseous- and Liquid-Fueled Engines	Stationary and portable engines >50 bhp, landfill and digester gas-fired		Rule	2/1/2008	<500 bhp: 45 x ECF[19] ppmvd @ 15% O_2 ≥500 bhp: 36 x ECF ppmvd @ 15% O_2 --- On and after 7/1/2012: 11 ppmvd @ 15% O_2	2,000 ppmvd @ 15% O_2 --- On and after 7/1/2012: 250 ppmvd @ 15% O_2	250 x ECF ppmvd @ 15% O_2 --- On and after 7/1/2012: 30 ppmvd @ 15% O_2	N/A	N/A
2	ARB DG Guidance[20]	Waste gas-fired reciprocating engine used in electrical generation (that are required to obtain a district permit)	Lean-burn technology, pre-stratified charge system	BACT	2002	0.6 g/bhp-hr; 50 ppmvd @ 15% O_2; 1.9 lb/MWh	2.5 g/bhp-hr; 300 ppmvd @ 15% O_2; 7.8 lb/MWh	0.6 g/bhp-hr; 130 ppmvd @ 15% O_2; 1.9 lb/MWh	N/A	N/A
3	Hill Canyon Wastewater Treatment Plant; Camarillo, CA – 2 units	396 bhp sewage digester gas-fired IC engines, producing 250 kW each	Catalytic carbon control systems for removing H_2S and ROCs, lean burn technology, turbocharged and aftercooled, low NO_x combustion chambers	Permit		0.6 g/bhp-hr OR 35 ppmvd @ 15% O_2	*13.6 g/bhp-hr;* 1200 ppmvd @ 15% O_2	*1.0 g/bhp-hr;* 28 ppmvd @ 15% O_2	Fuel: 20 ppmvd	N/A

[19] ECF is the efficiency correction factor. ECF = 1.0 unless the engine operator has measured the engine's net specific energy consumption, in compliance with ASME Performance Test Code PTC 17-1973, at the average load of the engine (see rule for details).

[20] Emission levels based on permit and source test data from the following facilities: City of Stockton, Hemet/San Jacinto Regional Water Reclamation Facility, South East Regional Reclamation Authority (Dana Point).

Table D-23. Sewage Digester Gas-Fired Reciprocating Internal Combustion Engine

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
4	San Bernardino City Municipal Water Dept.; San Bernardino, CA – 2 units	999 bhp sewage digester gas (w/ natural gas augmentation)-fired IC engine	Lean burn technology, turbocharged and aftercooled	Permit		0.6 g/bhp-hr; 36 ppmvd @ 15% O_2	2.5 g/bhp-hr; 2000 ppmvd @ 15% O_2	0.3 g/bhp-hr; 250 ppmvd @ 15% O_2	500 ppmv	0.1 gr/dscf @ 12% CO_2
5	San Bernardino City Municipal Water Dept.; San Bernardino, CA Unit 1	999 bhp sewage digester gas (w/ natural gas augmentation)-fired IC engine	Lean burn technology, turbocharged and aftercooled	Source test (85% load, 100% digester gas)	11/3 to 4/2005	0.2 g/bhp-hr; 13 ppmvd @ 15% O_2 (1 run)	1.3 g/bhp-hr; 115 ppmvd @ 15% O_2 (1 run)	0.1 g/bhp-hr; 18 ppmvd @ 15% O_2 TGNMNEO (2-run avg)	N/A	0.002 gr/dscf @ 12% CO_2 (1 run)
6	San Bernardino City Municipal Water Dept.; San Bernardino, CA Unit 2	999 bhp sewage digester gas (w/ natural gas augmentation)-fired IC engine	Lean burn technology, turbocharged and aftercooled	Source test (85% load, 100% digester gas)	11/1 to 2/2005	0.2 g/bhp-hr; 11 ppmvd @ 15% O_2 (1 run)	1.4 g/bhp-hr; 121 ppmvd @ 15% O_2 (1 run)	0.1 g/bhp-hr; 13 ppmvd @ 15% O_2 TGNMNEO (2-run avg)	N/A	0.001 gr/dscf @ 12% CO_2 (1 run)
7	San Francisco South East Treatment Plant; San Francisco, CA	21 MMBtu/hr sewage digester gas +/or natural gas-fired IC engine		Permit		0.5 g/bhp-hr	2.1 g/bhp-hr	0.6 g/bhp-hr (POC)	0.3 g/bhp-hr (equivalent to fuel H_2S content of 300 ppmv)	N/A
8	Stockton RWCF; Stockton, CA	1,408 bhp sewage digester/natural gas-fired IC engine	Lean burn technology, with precombustion chamber and siloxane scrubber	Source test (digester gas)	10/11 to 12/2006	0.4 g/bhp-hr; 22 ppm @ 15% O_2	2.6 g/bhp-hr; 264 ppm @ 15% O_2	0.1 g/.bhp-hr TNMHC	0.1 g/bhp-hr	<0.1 g/bhp-hr; <0.01 gr/dscf @ 12% CO_2

Table D-23. Sewage Digester Gas-Fired Reciprocating Internal Combustion Engine

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
9	BAAQMD Guideline 96.5.2	IC engine – digester gas fired, >50 bhp output	Lean burn technology, digester gas pretreatment to remove H_2S	BACT (AIP)	5/14/2009	1.25 g/bhp-hr	Initial standard: 2.65 g/bhp-hr Not to exceed standard: 3.77 g/bhp-hr CO emissions based / minimum overhaul schedule	1.0 g/bhp-hr	0.3 g/bhp-hr	N/A
10	BAAQMD Guideline 96.5.2	IC engine – digester gas fired, >50 bhp output	Digester gas pretreatment w/ >80% H_2S removal	BACT (tech. feasible)	5/14/2009	1.0 g/bhp-hr	2.1 g/bhp-hr	0.6 g/bhp-hr	N/A	N/A

Table D-24. Manure Digester and Co-Digester Gas-Fired Reciprocating Internal Combustion Engine										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	SCAQMD Rule 1110.2 Emissions from Gaseous- and Liquid-Fueled Engines	Stationary and portable engines >50 bhp, landfill and digester gas-fired		Rule	2/1/2008	<500 bhp: 45 x ECF[21] ppmvd @ 15% O_2 ≥500 bhp: 36 x ECF ppmvd @ 15% O_2 --- On and after 7/1/2012: 11 ppmvd @ 15% O_2	2,000 ppmvd @ 15% O_2 --- On and after 7/1/2012: 250 ppmvd @ 15% O_2	250 x ECF ppmvd @ 15% O_2 --- On and after 7/1/2012: 30 ppmvd @ 15% O_2	N/A	N/A
2	Fiscalini Farms & Fiscalini Dairy; Modesto, CA	1,057 bhp Guascor Model SFGLD-560 dairy digester gas-fired lean-burn IC engine driving 750 kW generator	Oxidation catalyst, SCR	Authority to Construct	12/17/2008	0.15 g/bhp-hr (11.0 ppmvd @ 15% O2) and shall not exceed 0.60 g/bhp-hr (44 ppmvd @ 15% O2)[22] NH3 limit: 10 ppmvd @ 15% O2	1.75 g/bhp-hr (210 ppmvd @ 15% O2)	0.13 g/bhp-hr (28 ppmvd @ 15% O2)	Fuel sulfur content ≤50 ppmv	0.036 g/bhp-hr

[21] ECF is the efficiency correction factor. ECF = 1.0 unless the engine operator has measured the engine's net specific energy consumption, in compliance with ASME Performance Test Code PTC 17-1973, at the average load of the engine (see rule for details).

[22] Permit includes a 24-month trial period to reduce NOx to the target 0.15 g/bhp-hr. The final NOx BACT level shall be determined by the District after 24 months operating history.

Table D-24. Manure Digester and Co-Digester Gas-Fired Reciprocating Internal Combustion Engine

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
3	ARB DG Guidance	Waste gas-fired reciprocating engine used in electrical generation (that are required to obtain a district permit)	Lean-burn technology, pre-stratified charge system	BACT	2002	0.6 g/bhp-hr; 50 ppmvd @ 15% O_2; 1.9 lb/MWh	2.5 g/bhp-hr; 300 ppmvd @ 15% O_2; 7.8 lb/MWh	0.6 g/bhp-hr; 130 ppmvd @ 15% O_2; 1.9 lb/MWh	N/A	N/A
4	Chino Basin Desalter Authority; Chino, CA – 2 units	1,158 bhp manure digester gas- or natural gas-fired IC engine, producing 1.9 MW combined	Lean burn technology, turbocharged and aftercooled, custom engine control, air/fuel module	Permit		*0.9 g/bhp-hr;* 47 ppmv @ 15% O_2 (@ 32.7% eff.)	*22.7 g/bhp-hr;* 2000 ppmv @ 15% O_2	*11.3 g/bhp-hr;* 325 ppmv @ 15% O_2 (@ 32.7% eff.)	N/A	N/A
5	BAAQMD Guideline 96.5.2	IC engine – digester gas fired, >50 bhp output	Lean burn technology, digester gas pretreatment to remove H_2S	BACT (AIP)	5/14/2009	1.25 g/bhp-hr	Initial standard: 2.65 g/bhp-hr Not to exceed standard: 3.77 g/bhp-hr CO emissions based / minimum overhaul schedule	1.0 g/bhp-hr	0.3 g/bhp-hr	N/A
6	BAAQMD Guideline 96.5.2	IC engine – digester gas fired, >50 bhp output	Digester gas pretreatment w/ >80% H_2S removal	BACT (tech. feasible)	5/14/2009	1.0 g/bhp-hr	2.1 g/bhp-hr	0.6 g/bhp-hr	N/A	N/A
7	Gallo Cattle Company; Atwater, CA	575 bhp Caterpillar Model G399NA rich burn digester gas-fired IC engine, producing 400 kW	3-way non-selective catalyst, PCV or equivalent, fuel sulfur scrubber	Permit	9/30/2012 (expiration date)	9.0 ppmvd @ 15% O_2 (or 0.15 g/bhp-hr)	1,100 ppmvd @ 15% O_2	20 ppmvd @ 15% O_2 as methane	Fuel sulfur limit of 59 ppmv as H_2S	0.1 g/bhp-hr

Table D-24. Manure Digester and Co-Digester Gas-Fired Reciprocating Internal Combustion Engine										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
8	Gallo Cattle Company; Atwater, CA	575 bhp Caterpillar Model G399NA rich burn digester gas-fired IC engine, producing 400 kW	3-way non-selective catalyst, PCV or equivalent, fuel sulfur scrubber	Source test	1/28/2010	3.18 ppmvd @ 15% O_2	384.64 ppmvd @ 15% O_2	11.19 ppmvd @ 15% O_2	<1.0 ppm fuel H_2S	N/A

Table D-25. Biomass Syngas-Fueled Reciprocating Internal Combustion Engine										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	SJVAPCD Guideline 3.3.14	Full-time rich burn IC engine, syngas-fueled[23]		BACT (AIP)	1/12/2009	9 ppmvd @ 15% O2	N/A	25 ppmvd @ 15% O2	N/A	N/A
2	SJVAPCD Guideline 3.3.14	Full-time rich burn IC engine, syngas-fueled		BACT (tech. feasible)	1/12/2009	5 ppmvd @ 15% O2	N/A	N/A	N/A	N/A

[23] Syngas (synthetic gas) is derived from biomass (agricultural waste) by gasification or similar processes. Syngas is distinguished from waste gases by its low methane content (<5%) and comparatively high hydrogen gas content (15% or greater), although frequently over half of the syngas composition is non-combustible gases such as nitrogen and carbon dioxide.

Table D-26. Landfill and Sewage Digester Gas-Fired Turbine										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	SJVAPCD Rule 4703 Stationary Gas Turbines (Tier 3 standards)	Stationary gas turbines ≥0.3 to 10 MW		Rule	9/20/2007	<3 MW: 9 ppmvd @ 15% O_2 3-10 MW (pipeline gas): 8 ppmvd @ 15% O_2 (steady state) and 12 ppmvd @ 15% O_2 (non-steady) 3-10 MW, <877 hr/yr: 9 ppmvd @ 15% O_2 3-10 MW, ≥877 hr/yr: 5 ppmvd @ 15% O_2	200 ppmvd @ 15% O_2[24]	N/A	N/A	N/A
2	SJVAPCD Rule 4703 Stationary Gas Turbines (Tier 3 standards)	Stationary gas turbines >10 MW		Rule	9/20/2007	Simple cycle and ≤200 hr/yr: 25 ppmvd @ 15% O_2 Simple cycle and >200 to 877 hr/yr: 5 ppmvd @ 15% O_2 Combined cycle[25]: 5 ppmvd @ 15% O_2	200 ppmvd @ 15% O_2[26]	N/A	N/A	N/A

[24] Exceptions to CO limit: GE Frame 7 = 25 ppmvd; GE Frame 7 with quiet combustors = 52 ppmvd; and <2.0 MW Solar Saturn driving centrifugal compressor = 250 ppmvd.
[25] Tier 2 standard; there is no Tier 3 standard for combined cycle turbines.
[26] Exceptions to CO limit: GE Frame 7 = 25 ppmvd; GE Frame 7 with quiet combustors = 52 ppmvd; and <2.0 MW Solar Saturn driving centrifugal compressor = 250 ppmvd.

Table D-26. Landfill and Sewage Digester Gas-Fired Turbine

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
3	SCAQMD Rule 1134 Emissions of Oxides of Nitrogen from Stationary Gas Turbines	Stationary gas turbines ≥0.3 MW		Rule	Last amended 8/8/1997	0.3-<2.9 MW: 25 ppmvd @ 15% O_2 2.9-<10.0 MW[27]: 25 ppmvd @ 15% O_2 2.9-<10.0 MW: 9 ppmvd @ 15% O_2 2.9-<10.0 MW, no SCR: 15 ppmvd @ 15% O_2 ≥10 MW: 9 ppmvd @ 15% O_2 ≥10 MW, no SCR: 12 ppmvd @ 15% O_2 ≥60 MW, combined cycle, no SCR: 15 ppmvd @ 15% O_2 ≥60 MW, combined cycle: 9 ppmvd @ 15% O_2	N/A	N/A	N/A	N/A

[27] Utilizing fuel containing a minimum of 60% sewage digester gas by volume on a daily average.

Table D-26. Landfill and Sewage Digester Gas-Fired Turbine										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
4	BAAQMD Guideline 89.3.1	Gas turbine – landfill gas-fired	Water or steam injection or low-NOx turbine design; fuel selection; good combustion practice; strainer, filter, gas/liquid separator, or equivalent particulate removal device	BACT (AIP)	6/17/1999	25 ppmv @ 15% O_2	200 ppmv @ 15% O_2	N/A	150 ppmv sulfur limit as H_2S	Fuel gas pretreatment
5	ARB DG Guidance[28]	Waste gas-fired turbine rated at <50 MW used in electrical generation (that are required to obtain a district permit)	Water injection	BACT	2002	25 ppmvd @ 15% O_2; 1.25 lb/MWh	N/A	N/A	N/A	N/A
6	Ameresco Chiquita Energy, LLC; Valencia, CA – 2 units	53.13 MMBtu/hr landfill gas-fired turbine, simple cycle, producing 4.6 MW each	Ultra lean premix alular combustor, start up LPG augmentation	Permit		25 ppmvd @ 15% O_2	130 ppm @ 15% O_2	20 ppmv @ 15% O_2 as C6 OR 98% destruction	Fuel: 150 ppmv H_2S	N/A
7	Gas Recovery Systems, Inc.; Santee, CA	Landfill gas-fired turbine producing 3.108 MW		Permit		25 ppmvd @ 15% O_2	130 ppmvd @ 15% O_2	3.5 ppmvd @ 15% O_2 as CH_4	8.3 ppmvd @ 15% O_2	N/A
8	Gas Recovery Systems, Inc.; Santee, CA	Landfill gas-fired turbine producing 3.108 MW		Source test	12/1/2006	21 ppm @ 15% O_2 (2.540 MW)	32 ppm @ 15% O_2 (2.540 MW)	3.5 ppm @ 15% O_2 (2.540 MW)	2.8 ppm @ 15% O_2 (2.540 MW)	N/A

[28] Emission level based on the following: Joint Water Pollution Control Plant (Carson).

Table D-26. Landfill and Sewage Digester Gas-Fired Turbine										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
9	Gas Recovery Systems, Inc.; Santee, CA	Landfill gas-fired turbine producing 3.108 MW		Source test	11/23/2004	19 ppm @ 15% O_2; (2.642 MW)	32 ppm @ 15% O_2; (2.642 MW)	1.6 ppm @ 15% O_2; (2.642 MW)	2.9 ppm @ 15% O_2; (2.642 MW)	N/A
10	Los Angeles County Sanitation Districts; Los Angeles, CA	(3) 113 MMBtu/hr Solar Model MARS-90-13000 digester/natural gas-fired combined-cycle turbines with unfired HRSG driving a 5.1 MW steam turbine generator	Water injection (fuel minimum 60% by volume digester gas)	BACT (for NOx and CO)	9/24/2003	25 ppmvd @ 15% O_2	60 ppmvd @ 15% O_2	4.5 lb/hr; *0.04 lb/MMBtu*	1.3 lb/hr; *0.01 lb/MMBtu*	5.7 lb/hr; *0.05 lb/MMBtu*
11	SCAQMD Guidelines for Non-Major Facilities	Digester or landfill gas-fired turbine		BACT	1990, 10/20/2000	25 ppmvd @ 15% O_2	130 ppmvd @ 15% O_2	N/A	Compliance w/ Rule 431.1	Fuel gas pretreatment for particulate removal
12	Waste Management; Livermore, CA	(2) 57.4 MMBtu/hr Solar Centaur landfill gas-fired turbines producing 3.33 MW each (Units S-6 and S-7)		Permit		0.1567 lb/MMBtu (*38.7 ppmvd @ 15% O2*)	0.2229 lb/MMBtu (*90.4 ppmvd @ 15% O2*)	N/A	N/A	N/A

Table D-27. Composting

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	SCAQMD Rule 1133.2 Emission Reductions from Co-Composting Operations	Co-composting[29] (new)		Rule	1/10/2003			1. Conduct active composting w/in enclosure; 2. Conduct curing composting phase using aeration system under negative pressure for ≥90% of blower operating cycle; and 3. Vent exhaust from enclosure and aeration system to control device w/ ≥80% VOC and NH_3 control efficiency. OR Submit alternate plan w/ overall 80% VOC and NH_3 reduction		N/A

[29] Co-composting is composting where biosolids and/or manure are mixed with bulking agents to produce compost.

Table D-27. Composting

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
2	SCAQMD Rule 1133.2 Emission Reductions from Co-Composting Operations	Co-composting (existing)[30]		Rule	1/10/2003			Submit compliance plan demonstrating overall reduction of 70% VOC and NH_3 from baseline		N/A
3	SJVAPCD Rule 4565 Biosolids, Animal Manure, and Poultry Litter Operations	Composting / co-composting facilities that use ≥100 wet tons per year of biosolids[31], animal manure, or poultry litter as part of their operation		Rule	3/15/2007			<u><20,000 wet tons/yr</u>: Implement at least three Class One measures OR Implement at least two Class One and one Class Two measure for active composting <u>≥20,000 to <100,000 wet tons/yr</u>: Implement at least four Class One measures OR Implement at least three Class One and one Class Two measure for active composting		N/A

[30] Existing operations defined as those that began operations on or before January 1, 2003.
[31] Organic material from treatment of sewage sludge or wastewater.

Table D-27. Composting

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
								≥100,000 wet tons/yr: Implement at least four Class One and one Class Two measures for active composting OR Implement at least two Class One and one Class Two measures for active composting and one Class Two measure for curing composting		
4	Inland Empire Regional Composting Authority; Rancho Cucamonga, CA	Biosolids co-composting operation consisting of enclosed aerated static piles, including materials handling and storage	Biofilter, baghouse	Permit				80% control (80% control NH_3)		No limit in permit, but 99% control expected due to baghouse

Table D-27. Composting

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
5	Los Angeles County Sanitation District (dba Westlake Farms Co-Composting); Mt. Diablo Baseline & Meridian, CA	Co-composting operation consisting of negative aerated static piles, including materials handling and storage	Biofilter	Permit[32]				80% control (90% control NH_3)		N/A
6	South Kern Industrial Center, LLC; Taft, CA	Biosolids co-composting operation consisting of negative aerated static piles, including materials handling and storage	Biofilter	Permit[33]				80% control (80% control NH_3)		N/A

[32] ARB staff received a draft copy of the permit; however correspondence with the District indicates the permit has been issued.
[33] ARB staff received a draft copy of the permit; however correspondence with the District indicates the permit has been issued.

Table D-28. Emergency Diesel Reciprocating Internal Combustion Engine										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
1	SJVAPCD Guideline 3.1.1	Emergency diesel IC engine		BACT (AIP)	7/10/2009	Latest EPA Tier Certification level for applicable hp range	Latest EPA Tier Certification level for applicable hp range	Latest EPA Tier Certification level for applicable hp range	Very low sulfur diesel fuel (15 ppmw sulfur or less)	0.15 g/bhp-hr or latest EPA Tier Certification level for applicable hp range, whichever is more stringent
2	ATCM for Stationary Compression Ignition Engines	New stationary emergency standby diesel-fueled compression ignition engines >50 bhp – non-emergency use limited to 50 hr/yr		Regulation (title 17 CCR sections 93115 to 93115.15)	10/18/2007	Off-road compression ignition engine standards for an off-road engine of the model year and bhp rating of the engine stalled to meet the applicable PM standard, or Tier 1 standards[34]	Off-road compression ignition engine standards for an off-road engine of the model year and bhp rating of the engine stalled to meet the applicable PM standard, or Tier 1 standards	Off-road compression ignition engine standards for an off-road engine of the model year and bhp rating of the engine stalled to meet the applicable PM standard, or Tier 1 standards	CARB diesel (15 ppmw sulfur or less)	0.15 g/bhp-hr

[34] The option to comply with the Tier 1 standards is available only if no off-road engine certification standards have been established for an off-road engine of the same model year and maximum rated power as the new stationary emergency standby diesel-fueled compression ignition engine.

Table D-28. Emergency Diesel Reciprocating Internal Combustion Engine										
Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
3	ATCM for Stationary Compression Ignition Engines	New stationary emergency standby diesel-fueled compression ignition engines >50 bhp – non-emergency use limited to 51-100 hr/yr		Regulation (title 17 CCR sections 93115 to 93115.15)	10/18/2007	Off-road compression ignition engine standards for an off-road engine of the model year and bhp rating of the engine stalled to meet the applicable PM standard, or Tier 1 standards[35]	Off-road compression ignition engine standards for an off-road engine of the model year and bhp rating of the engine stalled to meet the applicable PM standard, or Tier 1 standards	Off-road compression ignition engine standards for an off-road engine of the model year and bhp rating of the engine stalled to meet the applicable PM standard, or Tier 1 standards	CARB diesel (15 ppmw sulfur or less)	0.01 g/bhp-hr
4	SCAQMD BACT Guidelines for Non-Major Polluting Facilities	IC Engine, Stationary, Emergency, Compression-Ignition, Other		BACT	10/3/2008	50≤hp<100: 4.7 g/kWh or 3.5 g/bhp-hr (Tier 3)[36] 100≤hp<175: 4.0 g/kWh or 3.0 g/bhp-hr (Tier 3) 175≤hp<300: 4.0 g/kWh or 3.0 g/bhp-hr (Tier 3) 300≤hp<750: 4.0 g/kWh or 3.0 g/bhp-hr	50≤hp<100: 5.0 g/kWh or 3.7 g/bhp-hr (Tier 3) 100≤hp<175: 5.0 g/kWh or 3.7 g/bhp-hr (Tier 3) 175≤hp<300: 3.5 g/kWh or 2.6 g/bhp-hr (Tier 3) 300≤hp<750: 3.5 g/kWh or 2.6 g/bhp-hr	50≤hp<100: 4.7 g/kWh or 3.5 g/bhp-hr (Tier 3)[37] 100≤hp<175: 4.0 g/kWh or 3.0 g/bhp-hr (Tier 3) 175≤hp<300: 4.0 g/kWh or 3.0 g/bhp-hr (Tier 3) 300≤hp<750: 4.0 g/kWh or 3.0 g/bhp-hr	On or after June 1, 2004, the user may only purchase diesel fuel with a sulfur content no greater than 0.0015% by weight (Rule 431.2)	50≤hp<100: 0.40 g/kWh or 0.30 g/bhp-hr (Tier 3) 100≤hp<175: 0.30 g/kWh or 0.22 g/bhp-hr (Tier 3) 175≤hp<300: 0.20 g/kWh or 0.15 g/bhp-hr (Tier 3) 300≤hp<750: 0.20 g/kWh or 0.15

[35] The option to comply with the Tier 1 standards is available only if no off-road engine certification standards have been established for an off-road engine of the same model year and maximum rated power as the new stationary emergency standby diesel-fueled compression ignition engine.
[36] These are all NOx+NMHC standards.
[37] These are all NOx+NMHC standards.

Table D-28. Emergency Diesel Reciprocating Internal Combustion Engine

Ref. No.	Facility Name	Basic Equipment	Method(s) of Control	Type of Document	Date of BACT Det., Permit, or Rule	Emissions, per unit				
						NOx	CO	VOC	SO_2	PM10
						(Tier 3) ≥750 hp: 6.4 g/kWh or 4.8 g/bhp-hr (Tier 2)	(Tier 3) ≥750 hp: 3.5 g/kWh or 2.6 g/bhp-hr (Tier 2)	(Tier 3) ≥750 hp: 6.4 g/kWh or 4.8 g/bhp-hr (Tier 2)		g/bhp-hr (Tier 3) ≥750 hp: 0.20 g/kWh or 0.15 g/bhp-hr (Tier 2)
5	BAAQMD Guideline 96.1.3	IC Engine – Compression Ignition: Stationary Emergency, non-Agricultural, non-direct drive fire pump, >50 bhp output	Any engine certified or verified to achieve the applicable standard, CARB diesel fuel (ultra low sulfur diesel)	BACT (AIP)	4/13/2009	Current Tier standard for NOx at applicable horsepower rating	More stringent of either 2.75 g/bhp-hr (319 ppmvd @ 15% O2) or the current Tier standard	Current Tier standard for POC at applicable horsepower rating	Fuel sulfur content not to exceed 0.0015% (wt) or 15 ppm	More stringent of either 0.15 g/bhp-hr or the current Tier standard

Table D-29. Off-Road Compression Ignition Engine Certification Standards in g/bhp-hr (g/kW-hr)[38]

Engine hp (kW)	Tier 1[39]					Tier 2				Tier 3				Tier 4					
	HC	NOx	CO	PM	Years	NMHC + NOx	CO	PM	Years	NMHC + NOx	CO	PM	Years	NMHC + NOx	NMHC	NOx	CO	PM	Years
50 - <75 (37 - <56)		6.9 (9.2)			1998 – 2003	5.6 (7.5)	3.7 (5.0)	0.30 (0.40)	2004 – 2007	3.5 (4.7)	3.7 (5.0)	0.22 (0.30)	2008 – 2012	3.5 (4.7)			3.7 (5.0)	0.02 (0.03)	2013+
75 - <100 (56 - <75)		6.9 (9.2)			1998 – 2003	5.6 (7.5)	3.7 (5.0)	0.30 (0.40)	2004 – 2007	3.5 (4.7)	3.7 (5.0)	0.30 (0.40)	2008 – 2011	3.5 (4.7)	0.14 (0.19)	0.30-2.5 (0.40-3.4)	3.7 (5.0)	0.01 (0.02)	2012 - 2013
															0.14 (0.19)	0.30 (0.40)	3.7 (5.0)	0.01 (0.02)	2014+
100 - <175 (75 - <130)		6.9 (9.2)			1997 - 2002	4.9 (6.6)	3.7 (5.0)	0.22 (0.30)	2003 – 2006	3.0 (4.0)	3.7 (5.0)	0.22 (0.30)	2007 – 2011	3.0 (4.0)	0.14 (0.19)	0.30-2.5 (0.40-3.4)	3.7 (5.0)	0.01 (0.02)	2012 - 2013
															0.14 (0.19)	0.30 (0.40)	3.7 (5.0)	0.01 (0.02)	2014+
175 - <300 (130 - <225)	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.4 (0.54)	1996 – 2002	4.9 (6.6)	2.6 (3.5)	0.15 (0.20)	2003 – 2005	3.0 (4.0)	2.6 (3.5)	0.15 (0.20)	2006 – 2010	3.0 (4.0)	0.14 (0.19)	0.30-1.5 (0.40-2.0)	2.6 (3.5)	0.01 (0.02)	2011 – 2013
															0.14 (0.19)	0.30 (0.40)	2.6 (3.5)	0.01 (0.02)	2014+
300 - <600 (225 - <450)	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.4 (0.54)	1996 – 2000	4.8 (6.4)	2.6 (3.5)	0.15 (0.20)	2001 – 2005	3.0 (4.0)	2.6 (3.5)	0.15 (0.20)	2006 – 2010	3.0 (4.0)	0.14 (0.19)	0.30-1.5 (0.40-2.0)	2.6 (3.5)	0.01 (0.02)	2011 – 2013
															0.14 (0.19)	0.30 (0.40)	2.6 (3.5)	0.01 (0.02)	2014+
600 - <750 (450 - <560)	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.4 (0.54)	1996 – 2001	4.8 (6.4)	2.6 (3.5)	0.15 (0.20)	2002 – 2005	3.0 (4.0)	2.6 (3.5)	0.15 (0.20)	2006 – 2010	3.0 (4.0)	0.14 (0.19)	0.30-1.5 (0.40-2.0)	2.6 (3.5)	0.01 (0.02)	2011 – 2013
															0.14 (0.19)	0.30 (0.40)	2.6 (3.5)	0.01 (0.02)	2014+
≥750 (≥560)	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.4 (0.54)	2000 – 2005	4.8 (6.4)	2.6 (3.5)	0.15 (0.20)	2006 – 2010						0.30 (0.40)	2.6 (3.5)	2.6 (3.5)	0.075 (0.10)	2011 – 2014
															0.14 (0.19)	2.6 (3.5)	2.6 (3.5)	0.03 (0.04)	2015+

[38] For California Exhaust Emission Standards and Test Procedures – Off-Road Compression-Ignition Engines, see title 13, California Code of Regulations, section 2423. For federal Nonroad Compression-Ignition Engine Certification Standards, consult title 40, United States Code of Federal Regulations, Chapter 1, Part 89, Subpart B and Part 1039, Subpart B.

[39] Engine manufacturers have several options for complying with NOx during the transitional implementation years of Tier 4, including a “phase-in/phase-out” or alternative NOx level approach.

Table D-29. Off-Road Compression Ignition Engine Certification Standards in g/bhp-hr (g/kW-hr)[38]																			
Engine hp (kW)	Tier 1[39]					Tier 2				Tier 3				Tier 4					
	HC	NOx	CO	PM	Years	NMHC + NOx	CO	PM	Years	NMHC + NOx	CO	PM	Years	NMHC + NOx	NMHC	NOx	CO	PM	Years
>750 - ≤1200 (560 - ≤900) Gen. only	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.4 (0.54)	2000 – 2005	4.8 (6.4)	2.6 (3.5)	0.15 (0.20)	2006 – 2010						0.30 (0.40)	2.6 (3.5)	2.6 (3.5)	0.075 (0.10)	2011 – 2014
															0.14 (0.19)	0.50 (0.67)	2.6 (3.5)	0.02 (0.03)	2015+
>1200 (>900) Gen. only	0.97 (1.3)	6.9 (9.2)	8.5 (11.4)	0.4 (0.54)	2000 – 2005	4.8 (6.4)	2.6 (3.5)	0.15 (0.20)	2006 – 2010						0.30 (0.40)	0.50 (0.67)	2.6 (3.5)	0.075 (0.10)	2011 – 2014
															0.14 (0.19)	0.50 (0.6)	2.6 (3.5)	0.02 (0.03)	2015+